DEVONIAN SHALE

UNCONVENTIONAL GAS SOURCES

NATIONAL PETROLEUM COUNCIL • JUNE 1980

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John F Bookout, Chairman—Committee on Unconventional Gas Sources

NATIONAL PETROLEUM COUNCIL

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PREFACE

By letter dated June 20, 1978, the National Petroleum Council, an industry advisory committee to the Secretary of Energy, was requested to prepare an analysis of potential natural gas recovery from coal seams, Devonian Shale, geopressured brines, and tight gas reservoirs. In requesting the study, the Secretary stated that:

> ...Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for cost and recovery of unconventional gas and should consider how government policy can improve the outlook. (See Appendix A for complete text of the Secretary's letter and a further description of the National Petroleum Council.)

To aid it in responding to this request, the National Petroleum Council established a Committee on Unconventional Gas Sources under the chairmanship of John F. Bookout, President and Chief Executive Officer, Shell Oil Company. R. Dobie Langenkamp, Deputy Assistant Secretary for Resource Development & Operations, Resource Applications, U.S. Department of Energy, served as Government Cochairman of the Committee. A Coordinating Subcommittee and four task groups, by source, were formed to assist the Committee. The Devonian Shale Task Group was chaired by John L. Moore, Consolidated Natural Gas Service Company, and cochaired by Jeffrey B. Smith of the Department of Energy. (Rosters of the study groups responsible for this volume are included in Appendix B.)

The National Petroleum Council's report on Unconventional Gas Sources is being issued in five volumes:

- Volume I - Executive Summary
- Volume II - Coal Seams
- Volume III - Devonian Shale
- Volume IV - Geopressured Brines
- Volume V - Tight Gas Reservoirs.

The Coal Seams, Devonian Shale, and Geopressured Brines volumes are being issued in June 1980 with the Executive Summary and Tight Gas Reservoirs volumes being issued in late 1980.

For each source, reserve additions and producing rates are calculated at five gas prices, three rates of return, and at least two levels of technology. Constant January 1, 1979, dollars were used in all analyses. The report presents estimates of what could happen under certain technical and economic circumstances and is not intended to represent a forecast of what will occur.

SUMMARY

The objectives of the Devonian Shale study are as follows:

- Estimate the in-place gas resource of Devonian Shale in the eastern United States.
- Project possible production volumes and reserve additions of recoverable gas at various price levels with current technology.
- Estimate the potential of new technology and its effect on production and reserve additions.
- Examine constraints of Devonian Shale development.
- Compare findings with other published studies.

The geologic distribution of Devonian Shale extends over one-fourth of the North American continent. Since the most significant known deposits are in the eastern United States, the scope of the study encompasses the Appalachian, Michigan, and Illinois basins. Devonian Shale is a collective name for the various shale strata that lie between the younger Berea Sandstone and the older Devonian carbonates. Although different geologic names to describe the shale are common, they are the same organic shale. In this report the term "Devonian Shale" is generally used; for clarity, however, the organic shale in the Michigan basin is referred to as "Antrim Shale" and in the Illinois basin as "New Albany Shale." Since most Devonian Shale production has occurred in the Appalachian basin, the majority of data are from this area.

The in-place gas resource was estimated for each basin, based on the volume of organic shale in each county and the average gas content. For the Appalachian basin, the black shale thickness was determined separately, using both the sample thickness figures identified by color (published by the U.S. Geological Survey) and the amount of shale radioactivity identified by gamma-ray well logs. The black shale thickness was subtracted from the total shale thickness to arrive at the gray shale thickness. Therefore, two estimates of the resource were calculated for the Appalachian basin, based on two black shale thicknesses. In the Michigan basin, the highly radioactive portion of Devonian (Antrim) Shale was identified from the lesser radioactive shale based on gamma-ray logs. This was similar to the log data resource determination for the Appalachian basin. In the Illinois basin, the resource was based on the total thickness of New Albany Shale, since there was insufficient information to delineate the black shale from the gray shale. Gas content values of 0.6 and 0.1 standard cubic feet of gas per cubic foot of shale for black shale and gray shale, respectively, were used for the Appalachian resource estimate. The same values of 0.6 and 0.1 standard cubic feet of gas per cubic foot of shale for the higher and lesser radioactive shale intervals, respectively, were selected for the Michigan basin. A gas

content of 0.62 standard cubic feet of gas per cubic foot of shale was applied to the total shale thickness in the Illinois basin.

Resource estimates for the Appalachian basin vary from a low of 225 trillion cubic feet (TCF) if only gas in the black shales as determined by gamma-ray logs is included, to a high of 1,861 TCF if sample thicknesses are used and both black and gray shales are included. The resource estimate obtained by using the log thickness is believed to be less subjective than the estimate using sample thickness based on color. The gas in place estimate for the Illinois basin is 86 TCF, and for the Michigan basin the estimate is 76 TCF. Since by definition the resource is the volume of gas in place, these estimates should not be interpreted as a recoverable resource.

The potential for recoverable gas was projected on the prognosis of technology development. The price of this gas, based on economics, was determined accordingly. This study defines the total producible gas as the amount of gas in place that can be recovered as a function of technology, irrespective of price, while potential reserve is that portion of recoverable gas that can be exploited at a given price.

It was assumed that the producing well life is 30 years. Devonian Shale wells sometimes produce over a much longer period of time, resulting in ultimate recoverable reserves that are greater than the 30-year reserves used in this study. The economic results are not materially affected by production beyond the 30-year period; however, the longer term production is recognized as an important addition to future gas supplies.

Estimated recovery of gas from Devonian Shale and economic projections were confined to the Appalachian basin. Although similar projections could have been made for the Illinois and Michigan basins, the very limited data available would make such estimates speculative. Since the Appalachian basin has probably the greatest potential of the three basins and already has significant production, in the near term it is more likely that expanded development of Devonian Shale will occur in that area.

Three levels of technology were considered in estimating the recoverable gas from the Appalachian basin. Table 1 gives estimates of the potential reserves and total producible gas as a function of five price levels at 10 percent after-tax rate of return (ROR) (base case). Similar estimates were calculated for 15 and 20 percent ROR's and these results are presented in the report.

The majority of Devonian Shale wells require some form of stimulation to increase production to an economic level. The traditional form of technology used has been well bore shooting. This method of stimulation is relatively inexpensive and achieves satisfactory results in formations where favorable geologic conditions exist. Over the last 10 to 15 years, conventional hydraulic fracturing technology has been adapted to stimulate shale wells.

TABLE 1

Summary of Producible Gas Estimates (Appalachian Basin)
(Constant 1979 Dollars and 10% ROR)

	Cumulative Potential Reserves (TCF) vs. Price ($/MMBtu)					Total Producible Gas (TCF)
	2.50	3.50	5.00	7.00	9.00	
Traditional Technology	3.3	8.5	11.4	14.9	16.6	25.3
Conventional Technology	7.3	14.5	19.5	23.5	27.0	37.4
Advanced Technology	11.8	20.1	27.2	32.9	38.9	49.9

Although hydraulic fracturing is typically more effective in stimulation than is well bore shooting, it also presents several unique problems in the shale formation. While there have been improvements in production technology, current techniques in exploration technology make it difficult to define both the areas of and intervals within Devonian Shale which have economic production potential.

Historical production from an estimated 2,741 Devonian Shale wells in 36 counties in four states (Kentucky, West Virginia, Ohio, and New York) were analyzed in order to develop a rationale for extrapolation of the production and reserves data to areas where there is no current production and to predict the volume of gas that can be produced under various economic conditions. It was originally intended to model the average well production decline for each county with the following general hyperbolic expression:

$$\text{Production Rate (PR)} = C_1 \left[1 + \frac{C_3}{C_2} t \right]^{-1/C_3}$$

where C_1, C_2, and C_3 are constants, PR is the production rate in thousand cubic feet per day (MCF/D), and t is the time in years.

When the actual production was matched, it was found that all the county decline curves could reasonably be represented by using values of C_2 and C_3 equal to 3.0 and 2.5, respectively. Average well production in each of the 36 counties was determined by a hyperbolic decline curve characterized by representative C_1 values for each county. After the C_1 values were determined for each of the counties, likely parameters were examined for possible correlation with C_1. These parameters included the total shale thickness, black shale thickness as determined by gamma-ray logs, sample black shale thickness, and depth. The thickness of the black shale as determined by gamma-ray logs was the only parameter that correlated with C_1 and can be expressed as a constant or linear coefficient factor. The average county black shale thickness as determined by gamma-ray logs was multiplied by the linear coefficient 0.213 to determine the average C_1 value for each county. This was used as the basis for the traditional case.

As previously mentioned, the majority of the wells analyzed in the historical data base were stimulated by well bore shooting. Also examined were production data from the more recently drilled Devonian Shale wells completed by hydraulic fracturing in both the primary shale areas and outside the primary areas. In the primary shale areas, the data indicated that conventional fracturing technology yielded higher production than did well bore shooting. In the other shale areas, however, the comparison was less certain. Therefore, C_1 values for both traditional well bore shooting and conventional fracturing technology were recognized in the economic analysis.

Improved shale productivity which might be expected from advanced extraction technology was studied. Equally important are new exploration methods to locate potential areas having better natural fractures within the shale formations. Improved diagnostic techniques are needed to better define the shale interval to be stimulated.

There is some limited experimental evidence to demonstrate that advanced stimulation technology can improve productivity over conventional stimulation techniques. On the basis of the available data, it was assumed that advanced technology would double the improvement of conventional technology over traditional technology. For example, a well characterized by a C_1 value of 70 MCF/D for traditional stimulation would be expected to have its C_1 value increased by 15 MCF/D to 85 MCF/D if stimulated by conventional technology. Based on advanced technology, the C_1 value would be increased by 30 MCF/D and such a well would be represented by a C_1 of 100 MCF/D. This was the basis for the advanced technology case.

The economic analyses were performed on a discounted cash flow after tax rate of return basis at rates of 10, 15, and 20 percent to determine the amount of potential reserves at various price levels. Capital costs and associated expenses attributed to the producer included leasehold acquisition, well investment, gathering line (exclusive of compression and suction trunklines), overhead, operating and maintenance (O&M), and dry hole risk. Other parameters included success ratio, royalty, and the British thermal unit (Btu) content of the gas.

It is the general practice for the purchaser in the Appalachian basin to bear the field cost of compressing the gas. With so many different producers operating within the same area, it is not feasible for each one to own separate facilities. Instead, the purchaser, which is normally a gas utility, will own and operate centralized compressor stations and will extend their suction trunklines into developing areas.

While the in-place resource estimate considered all lands within the boundary of the Devonian Shale basin, it was unrealistic to assume that all of the area could be drilled. Land use restrictions such as areas where drilling is prohibited, storage fields, and developed shale producing fields, were excluded from the total in-place resource area. Actual experience dictates that not all of the remaining potential drillable areas can be leased for drilling because of coal mining difficulties, landowners' refusal to lease, etc. A certain percentage of those properties actually leased will be subject to problems involving mineral title, right-of-way access, or other conflicts. The net drillable areas were considered on a county-by-county basis since the factors are variable from one area to another. Of a total in-place resource area of 111,100 square miles, it was estimated that 62,000 square miles could be drilled in the Appalachian basin.

Possible annual production and additions to reserves were estimated for the Appalachian basin based on the amount of drillable area, average well spacing of 160 acres, and low and high drilling rig schedules. The results are tabulated in Table 2 for each of the three technology cases, assuming the high growth drilling schedule. The incremental price of gas computed at an ROR of 10 percent is also given in the table.

The prices at which supplies could be developed (Table 2) represent the field price paid to the producer, exclusive of compressor facility costs. Add-on compression costs amount to between \$0.49 and \$0.68 per million Btu (MMBtu) for the 10 percent ROR case. These costs were escalated as the field price for gas to operate the facilities rose from \$2.50 to \$9.00 per MMBtu.

In considering the two different drilling rig schedules, the more moderate rig scenario assumed that there would be initially 12 rigs drilling Devonian Shale wells in 1980, with a 12 percent increase in rigs each succeeding year. This is similar to the growth rate of drilling rigs experienced between 1973 and 1979 in the Appalachian area, where presently 125 rigs are active. An accelerated or high growth rate was represented by 15 rigs drilling Devonian Shale in 1980, with 15 rigs added per year through the year 2000. This reflects the more recent Appalachian drilling in the last several years. All rigs were assumed to drill 35 productive wells per year based on actual experience.

The order in which the Devonian Shale wells would be drilled was based on the lowest price gas being produced first, which generally represents the highest productivity wells. The unit price of production was established geographically on a county-by-county basis by the discounted cash flow (DCF) economic model at the respective ROR's. All counties with prices less than \$2.50 per MMBtu were grouped together, while \$2.50 to \$3.50 per MMBtu represents the next higher grouping, etc. Beginning with the lowest price group, those counties would be drilled first in accordance with the respective drilling schedule. The counties in the next higher price category would then be developed, and so on.

TABLE 2

Potential Incremental Supply (Appalachian Basin)
High Growth Drilling Schedule
(Production & Reserve Volumes [BCF] and Price [$/MMBtu])
(Constant 1979 Dollars)

	1980	1985	1990	1995	2000
Annual Productive Wells Drilled	770	3,400	6,000	8,650	11,300
Cumulative Wells	770	12,500	37,300	75,300	126,400
Traditional Technology					
Annual Production Rate	15	190	430	620	690
Annual Reserve Additions	200	890	1,250	1,110	720
Cumulative Additions	200	3,300	8,800	14,300	18,400
Incremental Price @ 10% ROR	<2.50	<2.50	<5.00	<7.00	<12.00
Conventional Technology					
Annual Production Rate	17	220	550	865	1,005
Annual Reserve Additions	240	1,040	1,660	1,690	1,140
Cumulative Additions	240	3,800	11,000	19,600	26,100
Incremental Price @ 10% ROR	<2.50	<2.50	<3.50	<7.00	<9.00
Advanced Technology					
Annual Production Rate	21	270	700	1,110	1,355
Annual Reserve Additions	290	1,290	2,030	2,170	1,600
Cumulative Additions	290	4,800	14,000	25,100	34,500
Incremental Price @ 10% ROR	<2.50	<2.50	<3.50	<5.00	<9.00

Various factors were examined as possible constraints to the development of Devonian Shale production. The most easily recognized constraints are those in the near term. It is estimated that 13 percent (traditional) to 20 percent (conventional) of the total producible reserves (base case) can be drilled at a price of $2.50 per MMBtu or less. Currently, development is at a very moderate rate. Several reasons for this are: the excess availability of gas supply; suppressed Appalachian field prices; competition with conventional sources; and the possible inadequacy of the ROR (base case). In addition, a significant portion of the $2.50 gas is located within the known Devonian Shale producing areas which are already leased, and the demand will dictate when the gas will be produced, irrespective of price. In the longer term, it appears that while environmental and socioeconomic problems may hinder development to some extent, these are not expected to be major barriers. Drilling acreage may be considered a major constraint but is similar to that experienced by industry in conventional oil and gas development. Although significant gas production from Devonian Shale is dependent on a large number of wells to be drilled, the drilling scenarios represent reasonable rig buildup schedules based on recent industry performance. Rig availability should not be a constraint. A large amount of investment capital is required for drilling of the wells necessary to achieve the predicted production. During the 20-year period (1980 to 2000), it is expected that the industry will need about $31 billion (1979 dollars) to finance a Devonian Shale program. The concern is that other resource programs financed by industry will be competing for this capital and this may represent the most serious constraint.

The results of this study were compared with similar results of two earlier reports: the Office of Technology Assessment (OTA) report and the Lewin report. The OTA and Lewin reports are described in Chapter Eight, where the major results of this study and those reports are compared (Table 17). The results of this study are broader in scope and based on more extensive data than either the Lewin report or the OTA report. The assumptions and methodology used in the latter two reports were different from those in this study; therefore, the similarity of results may be coincidental.

The following conclusions can be drawn from the results of this study:

- The natural gas resource base in Devonian Shale is prodigious, ranging between 225 TCF and 1,861 TCF for the Appalachian basin alone.

- A linear correlation exists between initial well production rate (C_1) and black shale thickness determined by gamma-ray logs.

- Conventional hydraulic fracturing results in increased C_1 values over historical well bore shooting, the degree of improvement being a function of the C_1 value for well bore shooting.

- The area available for drilling in the Appalachian basin is 62,000 square miles or about 56 percent of the total area, which significantly reduces the available resource base.

- Significant levels of Devonian Shale gas production are possible over the next 20 years; however, the rate of production will be controlled by gas price and technology developments.

- About 15 TCF of producible gas from Devonian Shale using conventional fracturing technology can be produced at prices up to $3.50 per MMBtu for a 10 percent ROR.

- Insufficient production data for the Illinois and Michigan basins are available to estimate production levels within those areas.

- Although efforts by government and industry are being directed toward the development of advanced technology, further work is required to develop optimized stimulation methods and more reliable exploration techniques.

- The limited demonstrated success of production technology for Devonian Shale represents a serious barrier to early exploitation of the resource by industry.

CHAPTER ONE

INTRODUCTION

OBJECTIVES

This report assesses the potential of Devonian Shale in the eastern United States, the state of recovery technology, and the prospects of future natural gas supply from this source. A range of projections for possible production volumes and reserve additions of recoverable gas at various price levels are developed for current technology (traditional and conventional) and for advanced technology. Results of this analysis are compared with previously published studies dealing with similar estimates for Devonian Shale.

BACKGROUND

The first gas well drilled in 1821 at Fredonia, New York, produced gas from Devonian Shale nearly 40 years before the drilling of the famous Drake oil well. Later, Devonian Shale production was established in eastern Kentucky, extreme western and southern West Virginia, and over scattered areas in central and southern Ohio and along the southern edge of Lake Erie from Ohio into New York. The major Devonian Shale drilling has been confined to the Appalachian basin where about 9,600 wells are known to be producing from Devonian Shale. It is estimated that presently somewhere around 100 new productive shale wells are being drilled annually.

There are also commercially exploitable sandstone and siltstone beds within the geologic sequence of Devonian sediments. These are mostly prevalent in the northern portion of West Virginia and western Pennsylvania, occurring within the upper and lower geologic sequence of Devonian age. The shale and sandstone formations are widely different with respect to lithology, stratigraphy, reservoir properties, and producing characteristics. Therefore, the intent of this report is not to include Devonian age sandstone formations. Neither is it the purpose to include any other eastern tight gas producing formations of Mississippian, Silurian, or Ordovician age.

Devonian Shale is referred to by different names according to local geologic terminology. Common usage involves names such as "Ohio Shale," "Brown Shale," and "Chattanooga Shale" in the Appalachian basin, "Antrim Shale" in the Michigan basin, and "New Albany Shale" in the Illinois basin.

ANALYSIS OVERVIEW

The methodology of this study was to estimate the in-place gas resource of Devonian Shale, to project production volumes and additions to reserves achievable at prices between $2.50 and $9.00

per MCF (constant 1979 dollars), and similar projections for advanced recovery technologies. The basins considered in this study are the Appalachian, Michigan, and Illinois basins.

For the Appalachian basin, as much industry production and cost data as possible were accumulated on a county-by-county basis. From this information, it was possible to estimate the gas in place on a volumetric basis, to develop production forecasts based on the state-of-the-art technology, and to derive similar estimates for advanced technology.

The limited shale gas data in the Michigan and Illinois basins allowed only a general analysis as compared to the detailed treatment accorded the Appalachian basin. An estimate of the in-place gas was prepared for the Michigan and Illinois basins. However, to attempt an economic analysis of recoverable gas was considered too speculative to have much meaning.

CHAPTER TWO

RESOURCE

ORIGIN AND GEOGRAPHIC EXTENT

Shale is defined as a fine-textured laminated sedimentary rock formed by the diagenesis of muds and clays having mineral particles of microscopic size. Black shales are rich in organic matter and have a high carbon content per unit volume. These shales are of great thickness, extending over wide areas, and are of particular interest as a potential source of hydrocarbons.

The term Devonian refers to the geologic time of deposition; and the specific rock unit, Devonian Shale, is a collective name for the various shale strata that lie between younger Berea Sandstone and older Devonian carbonates. Devonian Shale was deposited some 350 million years ago in a shallow sea that covered approximately half of the present continental land mass of the United States. Erosion of the adjacent lands produced massive quantities of sediment and organic debris which were carried by rivers into this vast sea. Fine particles of sediment and organic matter settled to the bottom in quiet, toxic waters. Where the sites of deposition were in a reducing environment, that is, stagnant water, the organic matter was preserved and formed the black organic-rich mud.

The inland sea was eventually filled by further deposition of sediments. The weight of the subsequent overlying sediments and the heat from the earth's overburden pressure, combined with geochemical reactions, gradually transformed the organic mud into the black organic shale as we know it today. At one time these Devonian Shales covered nearly all of the mid-Continent area, but subsequent uplift and erosion have stripped away much of the shale so that the Devonian Shales which remain today cover approximately one-fourth of the North American continent. They are prominent in the eastern United States in areas where the shales have not been eroded, such as the Appalachian, Michigan, and Illinois basins. The specific geologic names assigned to the different intervals within Devonian Shale vary within the basin as well as between basins, but they are, in fact, the same organic shale.

The chemical reactions, heat, and pressure which transformed the mud to shale also produced natural gas from the entrained organic matter. Some of the produced gas migrated into adjacent porous rocks, such as sandstones, to form the more conventional gas reservoirs, whereas other gas remained locked in the nonporous shale. These shales have long been recognized as a hydrocarbon source, particularly the gas-bearing intervals associated with black shale beds.

RESOURCE ESTIMATION PROCEDURE

In this section, the resource estimation techniques and attendant nomenclature are discussed.

Resource Estimate Definition

There are several resource estimates that can be determined, depending upon the nomenclature and definitions employed. In this study, the resource estimate is defined as the amount of natural gas in place that "can escape from a rock volume under ambient conditions given sufficient time without any heat stimulation and without grinding the rock."[1] There is a distinct difference between the resource of the source rock and that which is potentially recoverable. In Chapter Five, production and reserve potential of Devonian Shale is discussed. Thus, in terms of recovery, potential reserve refers to the quantity of gas that can be commercially exploited and economically recovered at a given price; likewise, total producible gas is that portion of the gas in place that can be totally recovered.

Gray vs. Black Shales

Devonian Shale is composed of strata of "black" and "gray" shales. Black shale, rich in organic matter, has a much higher gas content than gray shale. The gas contents in the black and gray shales were determined separately for the Appalachian basin, and the resource estimates for each were added together to arrive at the total amount. A similar approach was followed in the Michigan basin by differentiating between the organic-rich and organic-lean intervals of Devonian (Antrim) Shale. In the Illinois basin, the resource of Devonian (New Albany) Shale was based on the total section, because distinction between black and gray shales was not possible. This was due to limited data, since there are very few radioactive well logs available.

Off-gassing Data

Values used for the gas content associated with black and gray shales were based on core off-gassing analyses obtained from various cored wells in the Appalachian and Illinois basins.

Unfortunately, there was no off-gassing information available in the Michigan basin. However, production vs. black shale thickness results indicate that Antrim Shale may have gas content characteristics similar to those of the shales in the Appalachian basin.

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[1]Smith, Eric C., A Practical Approach to Evaluating Shale Hydrocarbon Potential, Second Eastern Gas Shales Symposium, METC/SP-78 Vol. II, EGS-70, pp. 73-87.

Shale Thickness

Total shale thickness was defined in the Appalachian basin as the shale section between the base of the Berea Sandstone and the top of the Onondaga Limestone. Sandstone members that are present within this interval were excluded as explained in the Background section of Chapter One. In the Michigan basin, the formation from which shale gas could be produced is the Antrim Shale of Devonian age. Antrim Shale everywhere overlies the Traverse formation. In eastern Michigan, the interval between the Mississippian strata and the top of the Traverse forms the Antrim Shale. Moving westward across the basin, the upper Antrim grades laterally into a thick greenish gray shale called Ellsworth Shale. This gradual facies change makes it difficult to distinguish between the two formations. Where separate identifications could not be made in this transitional zone, the entire interval was included in the total thickness for the purpose of the resource analysis. In the western edge of the basin where Ellsworth Shale is recognizable, it was excluded because its lithology is different from Antrim Shale. For the Illinois basin, the total shale thickness consists of the New Albany Shale group, which is dominantly shale with some limestone and siltstone intervals.

Various geologic sources were used for the determination of the total shale thickness, primarily well log data in the Appalachian and Michigan basins and state geological survey maps for the Illinois basin.

The black shale thickness in the Appalachian basin was estimated using two different criteria. The first approach was based on log data, and the thickness of the black shale having a gamma-ray radiation greater than 230 API units[2] is referred to in this study as log black shale thickness (T). This is indicated later in the study as an important variable in estimating production from Devonian Shale. A second approach employed the U.S. Geological Survey data based on identification of black shale strata by color. This is referred to as sample black shale thickness in this study. Although the same names, black shale and gray shale, were used for identification purposes in the log and sample studies, this does not necessarily refer to the same intervals. In the Michigan basin, a similar approach was taken consistent with the Appalachian log analysis method. From previous works reported by Garland D. Ells,[3] the Antrim Shale was divided into specific intervals based

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[2]Where the standard API calibrated logs were not available, a judgment factor was applied based on the gamma-ray shift from the normal shale line.

[3]Ells, Garland D., An Appraisal of Known Antrim Shale and Berea Oil and Gas Pools in Michigan, Second Eastern Gas Shales Symposium, METC/SP-78 Vol. 1, EGS-88, pp. 280-290; Ells, Garland D., Stratigraphic Cross Sections Extending from Devonian Antrim Shale to Mississippian Sunbury Shale in the Michigan Basin, DOE Contract No. EX-76-C-01-2346, published November 1978.

on the degree of radioactivity from gamma-ray logs. These intervals of high radioactivity, 1A, 1C, and 2 (Ells classification), were considered to be organically rich, and for the purpose of this study they represent the log black shale thickness.

For the Appalachian and Michigan basins, the organic-lean or gray shale thickness was arrived at by subtracting the log (or sample) black shale thickness from the total shale thickness.

Contour maps of total shale thickness and black shale thickness were prepared as previously described for each basin. These maps are included in Appendix C, from which the county average thicknesses were obtained in computing the resource.

Area Extent

The resource areas within the three Devonian Shale basins judged to have gas potential are outlined in Figure 1. The contour maps in Appendix C show the boundary outline in greater detail. The areas selected represent the judgment and opinions of many individuals and most likely will change as more information is obtained in the future. Also, the shale beds underlying the Great Lakes in the Michigan and Appalachian basins were not included in the area figures. The total resource area amounted to 111,100 square miles in the Appalachian basin, 28,150 square miles in the Illinois basin, and 35,400 square miles in the Michigan basin.

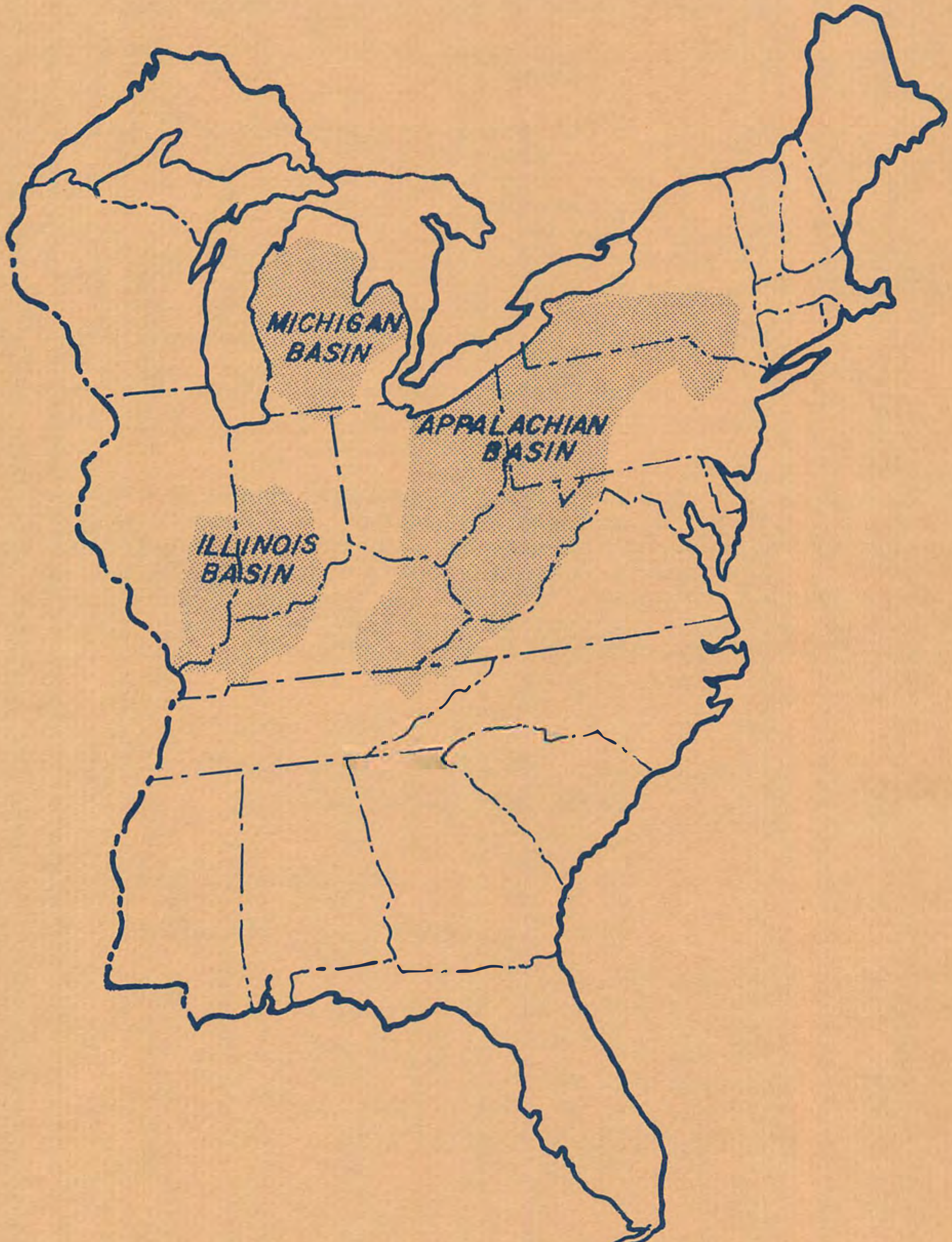
Method and Procedure

The in-place gas resource was calculated on a county-by-county basis for each basin. The technique considered the volume of organic shale and the average gas content, expressed as the volume of gas contained per unit volume of shale rock.

Appalachian Basin

Log data were available from about 75 percent of the total 233 counties in the Appalachian basin. In some counties, data from a large number of wells were available; so in this case sampling techniques were employed to arrive at the thickness. In some other counties, wells with usable log data were limited; in these cases extrapolation was employed to estimate the thickness. Gas content values of 0.6 and 0.1 standard cubic feet of gas per cubic foot of shale for the black and gray shales, respectively, were assumed to be representative over most of the basin. Table 3 exhibits off-gassing data from some of the recent cored wells in the Appalachian basin.

Using the areal extent of each county underlain by the shale, together with the average county shale thickness and gas content



THE AREA SHOWN REPRESENTS THAT PORTION WITHIN EACH BASIN CONSIDERED BY THIS STUDY TO HAVE SHALE GAS POTENTIAL AND DOES NOT NECESSARILY REPRESENT THE ENTIRE DEVONIAN SHALES THAT EXIST IN THE BASINS.

Figure 1. Geographic Outline of Potential Devonian Shale Areas.

values, the gas in place estimates for each county in the Appalachian basin were computed using the following equation:

Total gas in place = (Black shale thickness x Gas content of black shale

+ Gray shale thickness x Gas content of gray shale)

x Area

Substituting the gas content for the black and gray shales, the above equation is written as:

Total gas in place = (Black shale thickness x 0.6

+ Gray shale thickness x 0.1)

x Area

In addition to the log resource estimate where black shale thickness was based on the gamma-ray logs, the sample resource estimate was made using the same procedure. The sample black shale thickness in each county was obtained from the figures published by the U.S. Geological Survey.[4] Thus, two distinct resource estimates were made for the Appalachian basin, one derived from gamma-ray log data and the other from sample data.

TABLE 3

Average Off-Gassing Values of Seven Cored Wells in the Appalachian Basin

		Gas Content (Ft^3Gas/Ft^3Shale)		
		Average	γ-ray $\geq$230 API Units	γ-ray $\leq$230 API Units
EGSP/WV-5	Mason Co., WV	0.3	0.7	0.2
EGSP/WV-4	Lincoln Co., WV	0.3	0.7	0.1
EGSP/VA-1	Wise Co., VA	1.6	2.1	0.5
EGSP/KY-3	Martin Co., KY	0.3	0.4	0.1
EGSP/OH-2	Washington Co., OH	0.6	0.8	0.1
EGSP/WV-6	Monongalia Co., WV	unavailable	0.3	0.1
EGSP/NY-1	Allegany Co., NY	unavailable	0.3	0.1

Michigan Basin

The procedure used for the resource estimation was based exclusively on gamma-ray log data. Gas content data from cores were not available in the Michigan basin. However, based on well pro-

[4]de Witt, et al., 1978, U.S. Geological Survey, Map 1-917B.

duction similarity between the Michigan and Appalachian basins, values of 0.6 and 0.1 standard cubic feet of gas per cubic foot of shale were applied to the organic-rich shale and the organic-lean shale, respectively, in deriving the resource estimate. Since it is not known whether or not the gas content is uniform throughout the basin, it is recognized that these values are uncertain.

Illinois Basin

The procedure followed for estimating the resource in the Illinois basin used a single value for shale gas content based only on relative thickness of black shale intervals due to limited information on black and gray shale delineation. In establishing the gas content of Devonian Shale, data consisted of off-gassing from cores of one well in Illinois, four wells in Indiana, and one well in western Kentucky. The data were confined to the three black shale intervals within the New Albany Shale group, namely, Blocher Shale, Grassy Creek Shale, and Sweetland Creek Shale. Table 4 gives the average off-gassing values for each shale member from the six cored wells. Table 5 shows the relative thickness of the three black shale intervals expressed as a percentage of the total thickness for the New Albany Shale from the same cored wells.

From the data in Tables 4 and 5, a weighted average gas content value was derived as shown below.

Average gas content (SCF per cubic foot of shale) = (Grassy Creek Shale % thickness x Gas content of Grassy Creek Shale

+ Sweetland Creek Shale % thickness x Gas content of Sweetland Creek Shale

+ Blocher Shale % thickness x Gas content of Blocher Shale)

÷ 100

Substituting the percentage thickness and gas content values of Tables 4 and 5 gives:

Average gas content (SCF per cubic foot of shale) = $(0.66 \times 0.80) + (0.06 \times 0.97) + (0.13 \times 0.24)$

$= 0.62$

The following equation represents the gas in place estimate. The area and thickness values were determined on a county-by-county basis.

Total gas in place = Total shale thickness x 0.62 x Area

TABLE 4

Average Off-Gassing Values for the Black Shale Intervals of the New Albany Shale Group from Six Cored Wells in the Illinois Basin

		Black Shale Interval (Standard Cubic Foot Gas Per Cubic Foot Shale)		
		Grassy Creek	Sweetland Creek	Blocher
Hopson Oil Co.	Wayne Co., IL	0.69	No core	No core
EGSP/IND-1	Sullivan Co., IN	1.66	1.18	No samples
EGSP/IND-2	Clark Co., IN	0.17	0	0.04
EGSP/IND-3	Marion Co., IN	0.86	0.69	0
EGSP/IND-4	Jackson Co., IN	0.31	0.67	0.68
EGSP/KY-2	Christian Co., KY	0.62	1.35	Samples leaked
Weighted Average of Total Samples		0.80	0.97	0.24

TABLE 5

Thickness of Black Shale Intervals Expressed as Percentage of Total Thickness of New Albany Shale Group Based on Six Cored Wells in the Illinois Basin

		Black Shale Interval (Percent)		
		Grassy Creek	Sweetland Creek	Blocher
Hopson Oil Co.	Wayne Co., IL	58	6	18
EGSP/IND-1	Sullivan Co., IN	67	6	13
EGSP/IND-2	Clark Co., IN	93	0	7
EGSP/IND-3	Marion Co., IN	63	11	12
EGSP/IND-4	Jackson Co., IN	66	6	13
EGSP/KY-2	Christian Co., KY	51	8	14
Weighted Average Value		66	6	13

Results

In the Appalachian basin, considerable variation exists in the gas in place estimates depending on the approach taken. For instance, the Appalachian basin gas in place estimates vary from 225 TCF (if gas in only the black shales as determined by log data were included) to a total of 1,861 TCF (if sample thicknesses were used and black and gray shales were both included). Rather than present a single resource estimate for the Appalachian basin, the Task Group decided to present the gas in place estimates determined by the two approaches. It is felt, however, that the resource estimates obtained from using the log thicknesses are less subjective than the estimates obtained from the sample thicknesses based on color.

The resource estimate for the Michigan basin amounted to 76 TCF, and for the Illinois basin was 86 TCF. Specific data on the resource for the three basins can be found in Appendix D.

CHAPTER THREE

EXISTING PRODUCTION TECHNOLOGY[1]

DESCRIPTION OF RECOVERY METHODS

Traditional Techniques

For many years, there has been commercial production from Devonian Shale. A small percentage of Devonian Shale wells produce naturally (i.e., without stimulation) at commercial delivery rates, but the large majority of wells require some form of stimulation to achieve economic production. The traditional stimulation method involves the detonation of gelled nitroglycerine in the well bore over the producing interval. The formation face at the well bore is physically shattered by the explosion and, when the rubble is removed from the hole, the enlarged well bore diameter provides more effective gas communication between the formation and the well bore.

Well bore shooting is a relatively inefficient stimulation technique because of its limited radial effect, and because the explosive may be wasted on nonproductive portions of the shale. Nevertheless, it is relatively inexpensive and can be profitable in Devonian Shale where favorable geologic conditions exist.

Conventional Techniques

Variations of hydraulic fracturing technology developed for the sandstone formations have been adapted to stimulate shale wells over the last 10 to 15 years. Hydraulic fracturing is a method by which fluid, sand, and chemicals are injected into the formation under sufficient pressure to create fractures outward from the well bore. When the pressure is released, the fluid flows back, but the sand remains in the formation and acts as a proppant to keep the fracture from closing. This induced fracture creates a more effective surface area and a more direct path for the gas to flow from the formation into the well bore.

It is recognized that hydraulic fracturing is typically a more effective method of stimulation than well bore shooting. There is greater versatility in the completion techniques with hydraulic fracturing. The more favorable zone(s) can be isolated with production casing, and the fracturing treatment can be specifically directed into the formation with the highest potential for production.

Fracture stimulation of the shale formation presents a number of unique problems, such as fracture fluid removal from abnormally

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[1]Based on Appalachian basin data, and results apply to only that area.

low-pressured shale reservoirs, control of vertical and lateral fracture penetration, ineffective fracturing of the softer shales, and quality of cement bonding between the shale formation and the casing.

EXPLORATION TECHNIQUES

With current techniques, it is difficult to define both the areas of and intervals within Devonian Shale which have the best production potential. Natural fracturing has generally been postulated as the factor which has resulted in relatively high production rates. There is currently no direct method (other than drilling) of defining the extent of natural fracturing in Devonian Shale, either horizontally or vertically. Throughout the shale interval, a general relationship exists between gamma radiation, organic-rich black shale, and gas in place. However, the majority of in-place gas in the black shales may not be recoverable unless some sort of permeable path, either resulting from natural or man-made fracturing, exists to allow economic flow rates.

Presently there is limited exploration in Devonian Shale. The majority of wells drilled are either infill or step-out in the known areas. In those wells which are stimulated by well bore shooting, few logs are run and almost the entire shale interval is loaded with explosives and shot. For hydraulically fractured wells, the shale interval is cased and perforated prior to treatment and gamma-ray density logs are run to define the black shale zones. Temperature or sibilation logs are sometimes run to indicate zones of gas entry, which may be indicative of naturally fractured zones. Some operators simply perforate and fracture the thickest black shale zone, and others will perforate and stimulate the zones of gas entry.

HISTORICAL WELL DATA EVALUATION

Overview

Historical production data from areas of current Devonian Shale gas production were analyzed in order to develop a rationale for extrapolating the production and reserves data to areas where there is currently no production, and for predicting the volume of gas that can be produced under various economic constraints. From this analysis it was determined that the average well production in each county can be represented by a hyperbolic decline curve, and that this curve can be characterized by a single variable, C_1, for each county. Further, C_1 is shown to be correlatable with the black shale thickness determined from gamma-ray logs, and thus serves as an extrapolation tool.

Data Base

Historical production data from an estimated 2,741 wells in 36 counties in four states (Kentucky, West Virginia, Ohio, and New York) were provided to the National Petroleum Council (NPC) by the three major gas companies (Consolidated, Columbia, and Kentucky-West Virginia) operating in the Appalachian basin. For this study, it was decided to analyze these data on a county-by-county basis; however, owing to the proprietary nature of the production data, the actual identity of these counties will not be disclosed.

Although the amount of data available regarding Devonian Shale gas production is abundant, close examination of the data revealed the following known biases.

- Only about one-quarter of the wells completed in Devonian Shalé were individually metered. The remaining wells were metered in clusters with wells producing from other zones.

- Most of the data in this study are from presently active wells. Since the inactive wells tend to be poorer performers in general, this implies that the production data are biased in favor of the better wells. This tends to overestimate the predicted future recovery.

- The production figures may include production from sources other than Devonian Shale. For example, the wells were normally shot over the entire section or produced naturally from the open hole. These factors tend to overestimate the average well production if one holds to the strict classification of Devonian Shale.

- Wells drilled more than 30 years ago in older fields produced more gas than those drilled between 20 and 30 years ago. Gas wells with 20 or more years of production history were averaged together to increase the data base. This tends to decrease the predicted recovery for undrilled areas.

- The production data used represent the actual and not the theoretical production capability of the wells. Downtime is included. While this could have a marked effect on physical interpretation, the actual production is better for the prediction of future production.

Well Production Performance by County

To develop a rationale for extrapolating the production and reserves to areas where there is currently no gas production from Devonian Shale, the historical production data were critically examined and analyzed to detect trends and identify potential correlations with reservoir parameters. As a first step, a decline curve, or the corresponding derived cumulative production curve, was prepared for each county from the average values calculated from supplied data. This average well decline for the county was then represented by a hyperbolic curve of the form:

$$\text{Production Rate (PR)} = C_1 \left[1 + \frac{C_3}{C_2} t \right]^{-1/C_3} \qquad \text{(Eq. 1)}$$

PR is the production rate in MCF/D and t is the time in years when C_2 is in years and C_3 is dimensionless. C_1 thus represents the initial production rate in MCF/D at time (t) = 0.

The original intent was to characterize the average well decline curve for each county by a hyperbolic decline curve by developing a set of values of C_1, C_2, and C_3 for each county. However, it turned out that all the county decline curves could be reasonably represented by common values of C_2 and C_3 held at 3 and 2.5, respectively. By substituting these C_2 and C_3 values into Equation 1, the hyperbolic expression becomes:

$$PR = C_1 \left[1 + \frac{5}{6} t \right]^{-\frac{2}{5}} \qquad \text{(Eq. 2)}$$

The parameter C_1 thus serves as a single parameter for characterizing the average decline curve for each county. Thus, C_1 is related to other quantities of interest as follows:

cumulative first year production (MMCF) = 0.32 C_1
10-year cumulative production (MMCF) = 2.06 C_1
20-year cumulative production (MMCF) = 3.36 C_1
and 30-year cumulative production (MMCF) = 4.43 C_1

Figure 2 illustrates the shape of the decline curve as a function of three different C_1 values of 100, 65, and 40 MCF/D, respectively.

It is pointed out that the fit of the data to the hyperbolic decline curve was primarily for developing a rationale for extrapolation, and should not be construed as necessarily indicative of reservoir mechanisms or as a sole tool for exploration and production.

Comparison of Fitted Decline Curves with Actual Data

In order to depict how well the production model (Equation 2) matches the data and to describe the process of handling the data, two examples are presented below. The first discusses data from a single county and the second shows how the data from all 36 counties were tabulated.

Individual County

One specific county is used to illustrate the process of matching the data to give an idea of the match for an individual county,

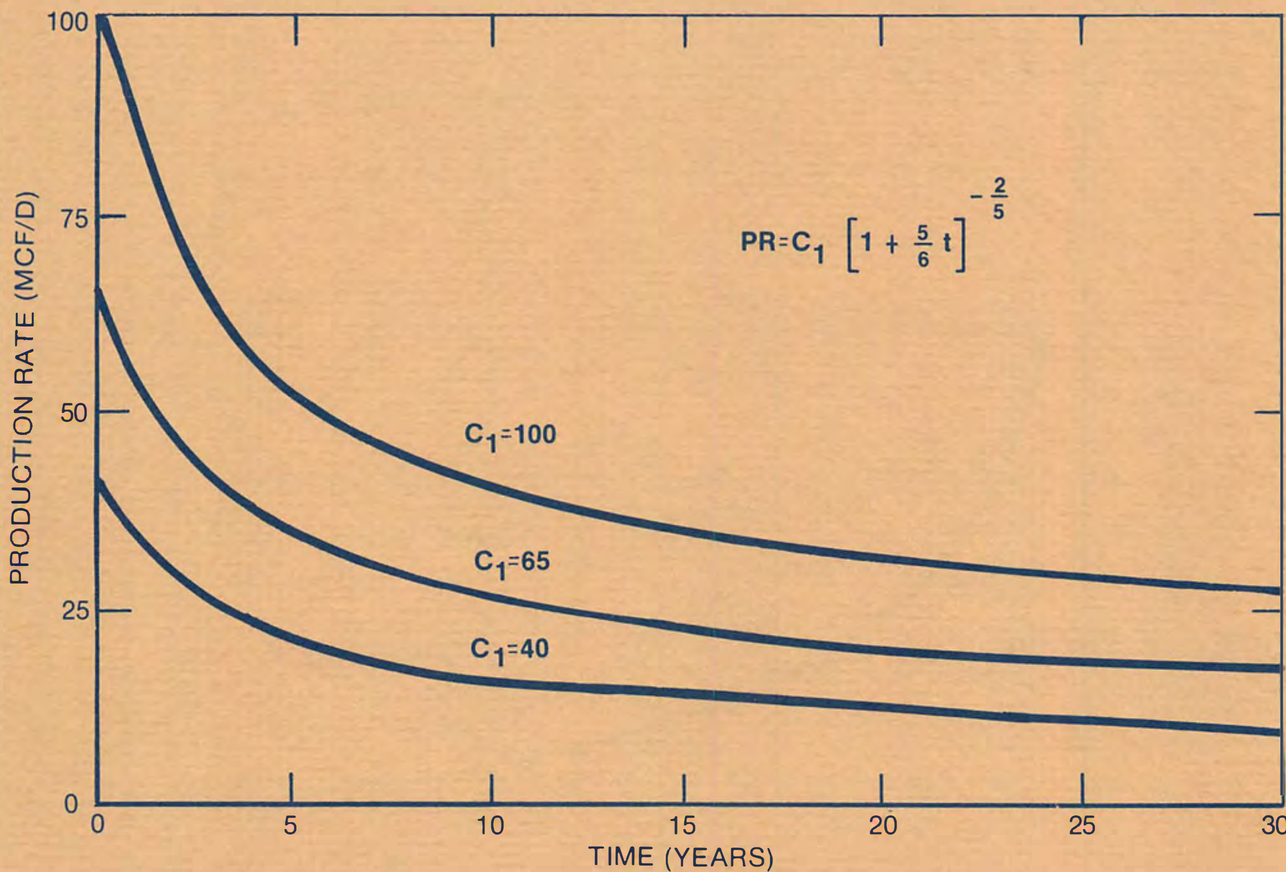

Figure 2. Example of Production Decline for Several Different C_1 Values.

and to demonstrate how the individual county data were developed into the overall fit. Figure 3 shows the decline curve based on C_1 = 130 MCF/D determined as the mean C_1 average for the specific county. This is plotted as production rate and cumulative production vs. time. These are plots of the hyperbolic decline curve controlled by the coefficients shown on the graph. Two sets of production data were available for this county. One company furnished a set generated by choosing 20 wells at random from their records. The average well production rate from these data were plotted as black dots for each year through the 20th year (upper curve). The same data were used to produce the related average cumulative production for each year and plotted as X's. The second set of data from this county consisted of first-year, 10-year, 20-year, and 30-year cumulative production for each of 173 wells (different company). The average data for this set are shown as large circles.

The C_1 value of 130 matched both sets of data for the county. In spite of all the limitations and differences in procedures between the two companies, it is obviously an excellent fit of both sets of data for this county. For the second set of data, the C_1 value predicted the 10-year production as 5 percent over the data supplied, and the 20-year production as 1 percent under the data supplied. Although not shown on the figure, the 30-year data were also available for this county. When fitted to 10-, 20-, and

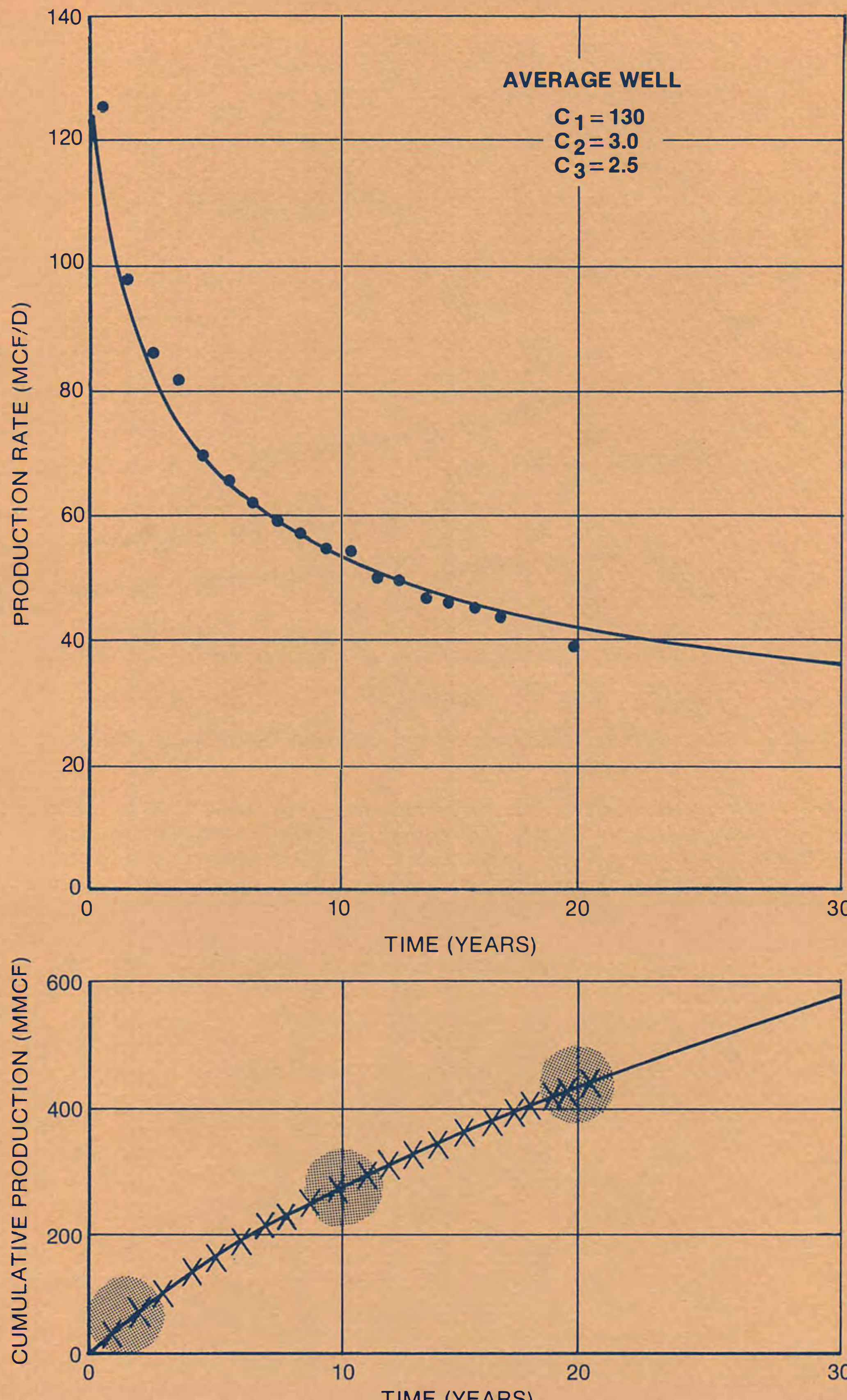

Figure 3. Example of Average Well County Production.

30-year average data, the calculations were, respectively, 5 percent over, 1 percent under, and 3 percent under the production data supplied.

It is also important to show the variation of the values of C_1 within a county. The individual "best fit" C_1 values were determined for each of the 173 wells for the 10-, 20-, and 30-year production as shown in Figure 4. The values of C_1 within this county follow the classic log-normal distribution. The median C_1 of the actual data is 100, while the median from the straight line fit is 95. The mean of the individual C_1 values is also 130 (same as the fit to the average data above). Although not illustrated, the values of C_1 in other counties were also found to follow a log-normal distribution.

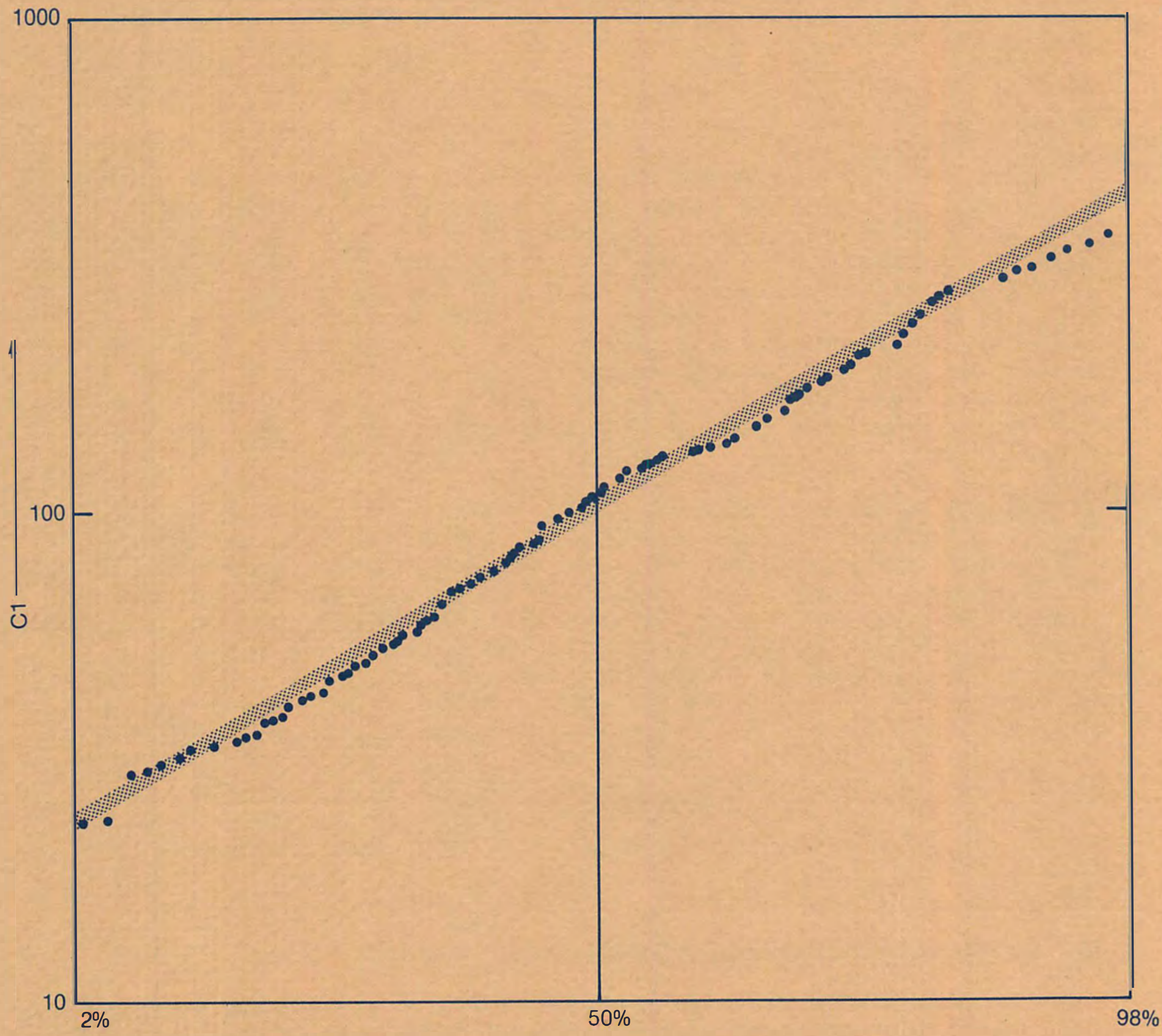

Figure 4. Example of Individual Wells' C_1 Distribution for a County.

All Counties

The preceding section illustrated how well the fitted decline curve matches all the data for the single county shown. In order to show how the data from all the counties match the model, an abbreviated tabulation of all the production data is illustrated in Table 6. The table shows three of the 36 counties used for the extrapolation of the data. The table illustrates that the fitted decline curves predict the 10- and 20-year cumulative production by 1.3 percent above and 0.1 percent below the production data, respectively. Standard deviations on the same numbers are 2.9 percent and 2.0 percent. Similar weighted averages are 1.6 percent above and 0.5 percent below the production data. These weighted standard deviation percentages are 1.7 and 1.0, respectively. These are given to show that C_1 values generated for counties represented by many wells predict the data better than those with only a few wells.

EXTRAPOLATION RATIONALE

After the mean average C_1 values were determined for each of the counties for which there is production, an attempt was made to correlate these values with parameters that could be quantified and that would likely have a physical relationship. Parameters examined for possible correlation with C_1 included total shale thickness, black shale thickness as determined by gamma-ray logs, sample black shale thickness, and depth. The only parameter that did correlate with C_1 was the thickness of the black shale as determined by gamma-ray logs. The residuals from this correlation were checked against the remaining parameters without apparent sign of correlation.

Figure 5 shows a plot of the C_1 values for each of the 36 counties vs. the average black shale thickness for the corresponding county as determined from the gamma-ray black shale thickness. The stippled central line shows the best correlation when forced through the origin. This relationship provides input to the model used for the gas price estimates. The average black shale thickness as determined by gamma-ray logs is multiplied by the linear coefficient 0.213 to determine the average C_1 value for that county. This is the basis used for the traditional shooting stimulation case. The two bounding thin lines on either side of the stippled line represent the 95 percent confidence limits (fitted through zero) used in the economics sensitivity study in Chapter Five. These are C_1 = 0.184 and 0.241 times the log thickness, respectively.

EVALUATION OF PRODUCTION TECHNOLOGY

Actual production from over 2,700 wells previously discussed in this chapter represents the historical data base of wells stimulated by well bore shooting (traditional method) and, to a lesser extent, from naturally produced wells.

TABLE 6

County Production Data with Comparison to Estimates

County	Number of Wells*	Averaged Data: 10-Yr. Cum. Prod. (MMCF)	Averaged Data: 20-Yr. Cum. Prod. (MMCF)	Fit C_1 MCF/D	(Fit − Data)/Fit x 100: 10-Yr. Cum. Prod. (%)	(Fit − Data)/Fit x 100: 20-Yr. Cum. Prod. (%)
1	346	265	440	130	+ 1.1†	− 0.7†
2	120	242	394	118	+ 0.4	+ 0.5
.	.	.	.	.	.	.
.	.	.	.	.	.	.
.	.	.	.	.	.	.
36	28	Combined data§		70	--	--
	$\sum = 2,741$	Unweighted statistics¶			N = 15	N = 15
					$\overline{X} = 1.3\%$	$\overline{X} = -0.1\%$
					$S = 2.9\%$	$S = 2.0\%$
		Weighted statistics¶			N = 2,321	N = 2,321
					$\overline{X}_w = 1.6\%$	$\overline{X}_w = -0.5\%$
					$S_w = 1.7\%$	$S_w = 1.0\%$

*This is an estimation of the number of wells from which data were drawn. It is not equal to the number of wells in the county. In some counties it includes an estimate of the population from which a random sample was drawn.†

†Fifteen of the 36 counties with 2,321 wells of the 2,741 wells have data that can be directly compared to a fit predicted by the C_1 value chosen. For each county with comparable data, such as counties 1 and 2, the difference between the fit and the data is given in percent for the 10- and 20-year cumulative production.

§The data from the rest of the 36 counties do not allow a direct comparison of the fitted data with actual 10- and 20-year production. In many of these counties, C_1 was obtained from ultimate reserve figures; C_1 for some other counties (e.g., county 36) was derived from combined types of data and therefore the fit cannot be compared directly with the actual data.

¶Two sets of statistics are presented. The upper set is unweighted and simply averages the percentage difference for each category and gives the standard deviation for the 15 counties with comparable data. The lower set repeats this but does it by weighting each well equally rather than each county. The upper set is valid for most purposes but the lower set eliminates a few extremes generated by meager data in some counties.

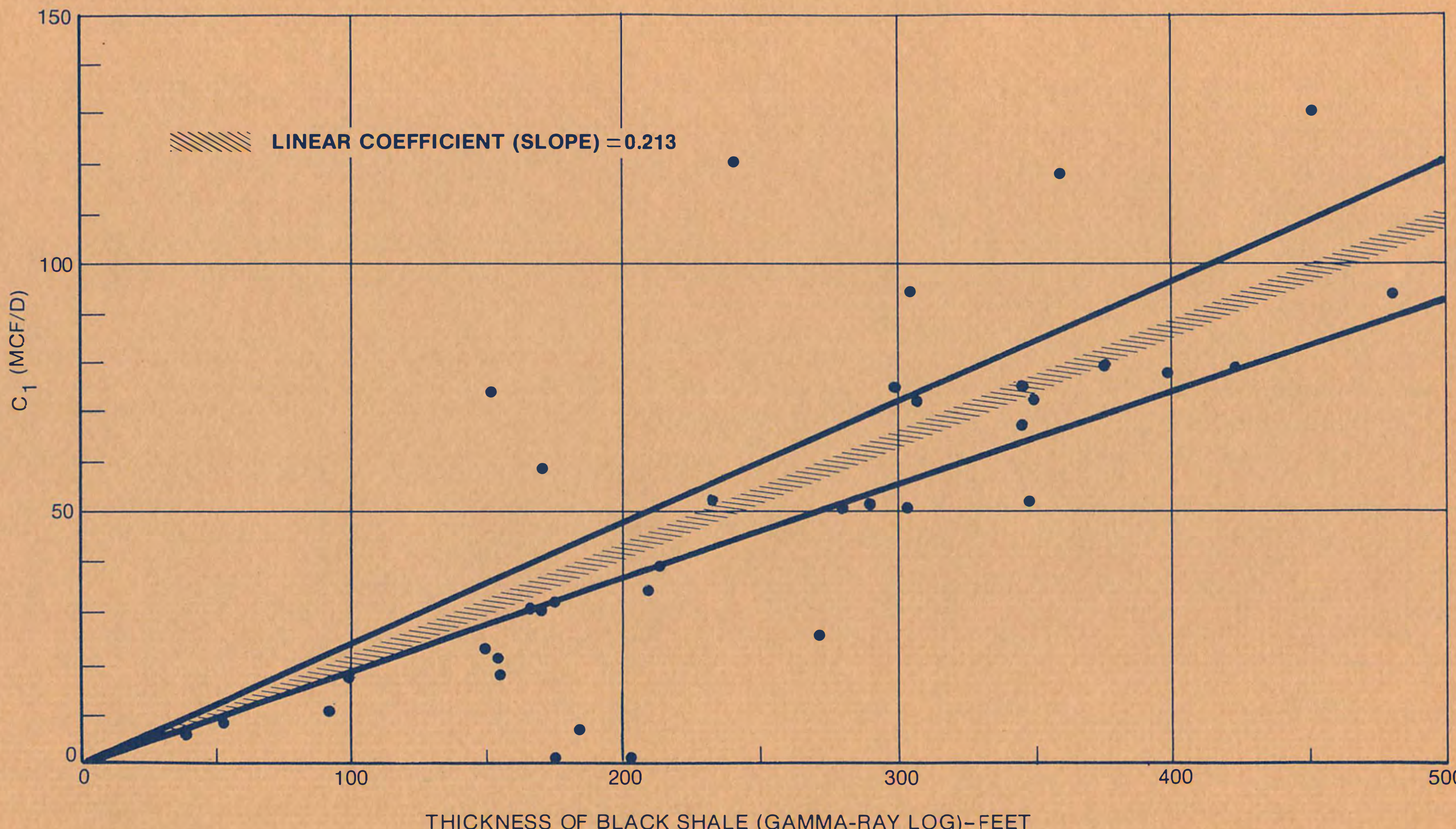

Figure 5. C_1 vs. Log Black Shale Thickness.

The more recently drilled Devonian Shale wells completed by hydraulic fracturing in the primary shale-producing areas of eastern Kentucky and southern West Virginia were examined, together with shale wells fractured outside of the primary shale areas. In the primary shale areas the data indicated that conventional fracturing technology yielded substantially better results over well bore shooting. It was concluded that the production from the traditional shot wells would have been higher if conventional fracturing had been used. Therefore, the individual county C_1 values determined from historical data were upgraded to reflect the current state of technology (i.e., conventional fracturing).

In other shale areas, however, fractured wells have not been as successful and the wells do not always appear to respond to hydraulic fracturing in a favorable manner. To illustrate that fracturing has not been universally preferred over shooting, Table 7 lists the number of completed fractured wells and shot wells from 1970 through 1978. It remains to be demonstrated whether the improvement due to conventional fracturing can be achieved throughout the untested shale areas. For this study, it was decided that both traditional C_1 values and upgraded C_1 values for conventional technology would be used in the economic analysis (Chapter Five).

TABLE 7

Stimulation Results and Approximate Number of Completed Devonian Shale Wells Drilled by Industry Between 1970 and 1978

	Appalachian Basin		
	Annual Shale Wells Drilled*	Annual Shale Wells Stimulated†	
Year		Shot	Frac
1970	51	27	18
1971	45	24	16
1972	60	21	36
1973	100	62	27
1974	63	40	14
1975	75	54	11
1976	88	67	14
1977	68	38	25
1978	76	46	22

*The difference between total productive wells and the stimulated wells is the number of wells completed without stimulation.

†Wells with no stimulation treatment reported were assumed to be completed naturally.

SOURCE: Petroleum Information Corporation.

The rationale for upgrading the historical production data was based on published information by Edward O. Ray.[2] Ray's study compared the first five years' production of approximately 250 productive shale wells in eastern Kentucky. These wells were either shot with explosives in open hole or were fractured with more or less standard treatments of 1,000 barrels of gelled water and 50,000 pounds of sand. Ray grouped the wells by open flow and compared annual production between the two methods of stimulation for open flow ranges of 0-100 MCF/D, 100-200 MCF/D, 200-300 MCF/D, and over 300 MCF/D.

Using this data, the best values of the hyperbolic C_1 constant were determined for the five year annual productions for shot and conventionally fractured wells in each open flow category. The interpretation of Ray's data is presented in Figure 6.

Improvement ratios for conventional fracturing relative to shot stimulation were derived for each open flow category by dividing the C_1 (fractured well) by the C_1 (shot well). The lowest open flow wells with less than 100 MCF/D benefited the most from fracturing, with a 57 percent improvement over shooting. In the open flow range of 100-200 MCF/D, fractured wells produced 40 percent better than shot wells, and in the 200-300 MCF/D grouping, fracturing improvement was 15 percent. Above 300 MCF/D, fracturing was no better than shooting.

The conventional fracturing improvement ratios for C_1 traditional shot well production is shown in Figure 7. With C_1's greater than 100, there is no improvement in production; i.e., improvement ratio equals zero, but as the shot well C_1's decrease below the 100 value, the improvement ratio increases linearly as indicated by the graph.

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[2] Ray, Edward O., <u>Devonian Shale Development in Eastern Kentucky</u>, National Academy of Science -- Symposium on Natural Gas from Unconventional Sources, 1976, pp. 100-112; Ray, Edward O., <u>Devonian Shale Production, Eastern Kentucky Field</u>, The Future Supply of Nature-Made Petroleum and Gas, UNITAR Conference, Pergamon Press, New York, 1976.

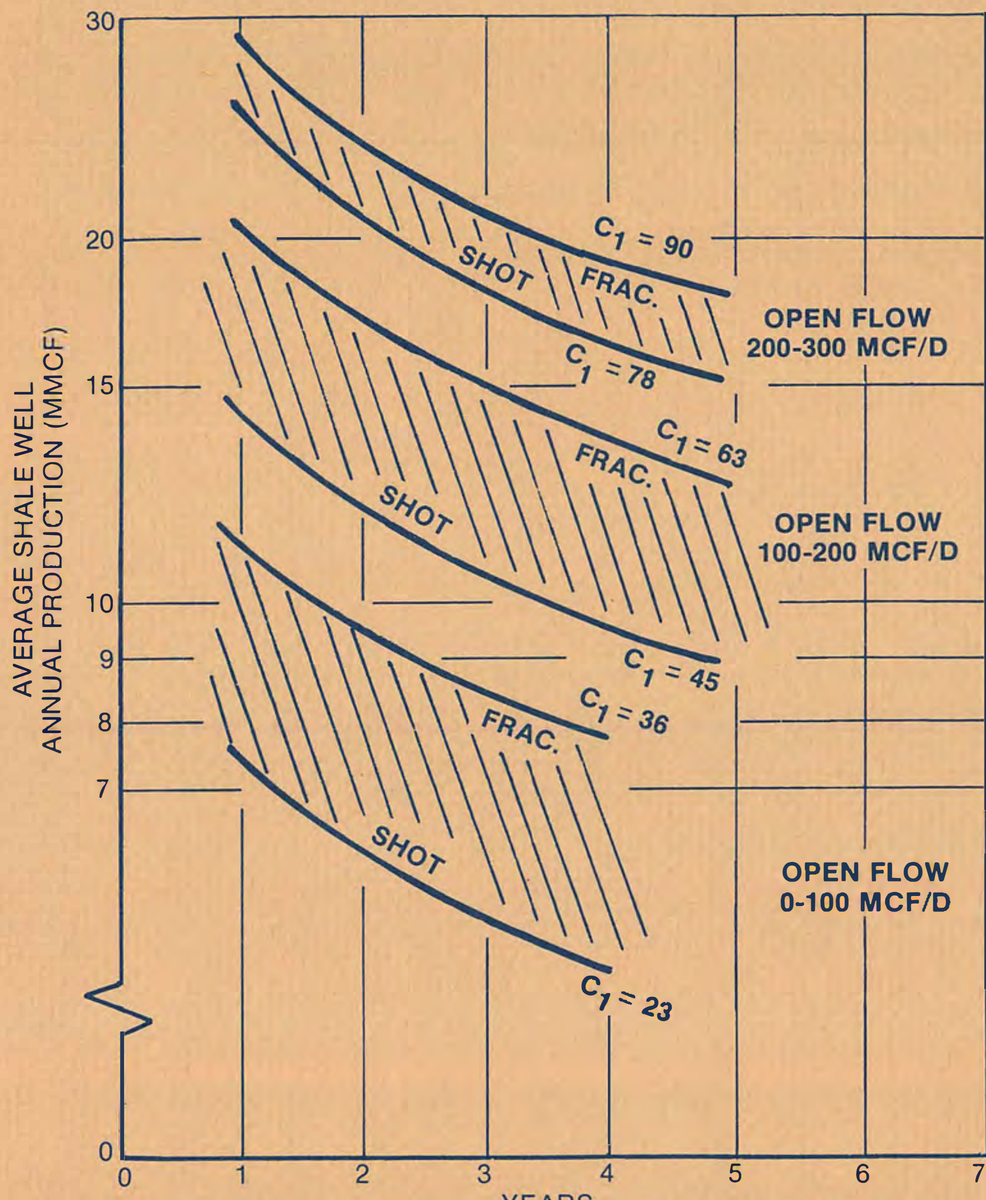

Figure 6. Comparison of Average Production Decline for Shot Well vs. Conventional Fractured Well (Interpretation of E.O. Ray Data [2]).

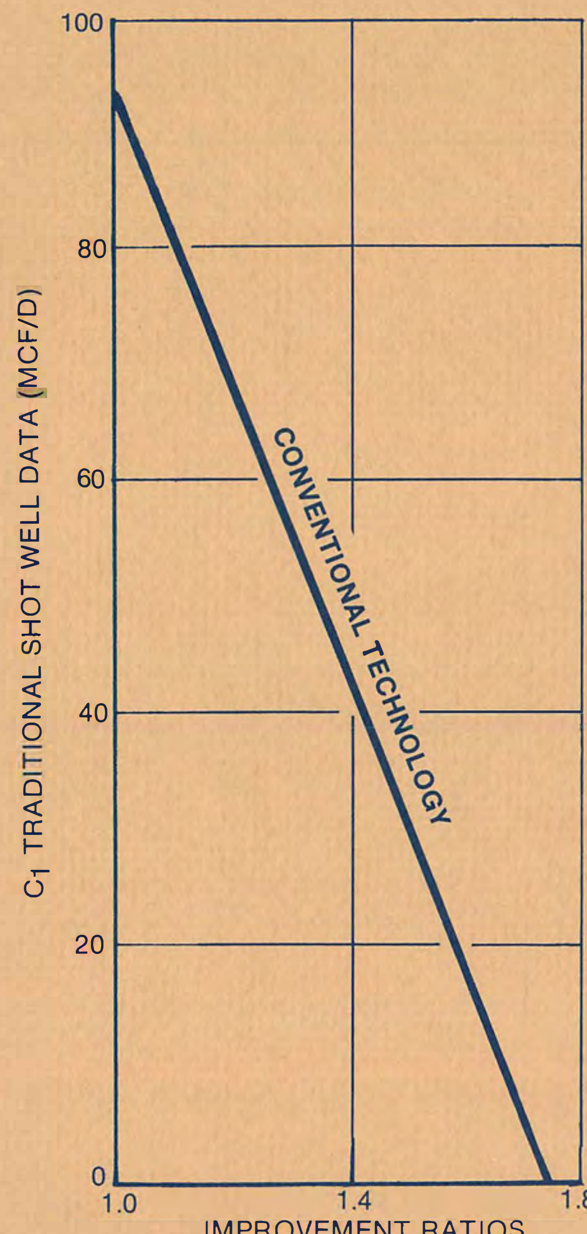

Figure 7. Improvement Ratios for Conventional Technology Relative to Traditional Shot Well C_1 Data.

CHAPTER FOUR

ECONOMIC PARAMETERS

COST ELEMENT LISTING

The following elements were used as inputs to the economic model:

- Well investment -- exclusive of stimulation cost
- Stimulation and cleanup cost
- Leasehold cost
- Exploration cost
- Dry hole cost
- Success ratio
- Well line cost
- Annual O&M cost
- Royalty
- Btu content
- Overhead
- Taxes
- Rate of return (ROR)
- Well life.

COST ELEMENT DESCRIPTION AND VALUES

Well Investment (Exclusive of Stimulation Cost)

This investment includes all drilling costs, exclusive of stimulation and associated completion costs, in 1979 dollars. It includes casing for fractured wells, but does not include perforating, stimulation, and cleanup costs. For shot wells, stimulation and cleanup costs are not included.

Actual well costs were compiled for recent Devonian Shale wells, covering a wide range of well depths. From these wells, the general relationships shown in Figure 8 were derived. This figure shows the drilling cost per foot vs. total well depth for uncased (shot) and cased (conventionally fractured) wells. The costs are about $6 per foot higher for fractured wells because of additional casing, cementing, and associated equipment required for fractured wells. As indicated in Figure 8, the costs per foot at shallow depths are high because of the fixed costs which do not vary with depth. Also, as well depth exceeds 6,000 feet, drilling costs per foot increase. The total nonstimulation well investment was calculated from this relationship and the well's total depth. The ground surface to the base of the Devonian Shale was assumed to be the total well depth. Included in Appendix C are isodepth contour maps of the three basins.

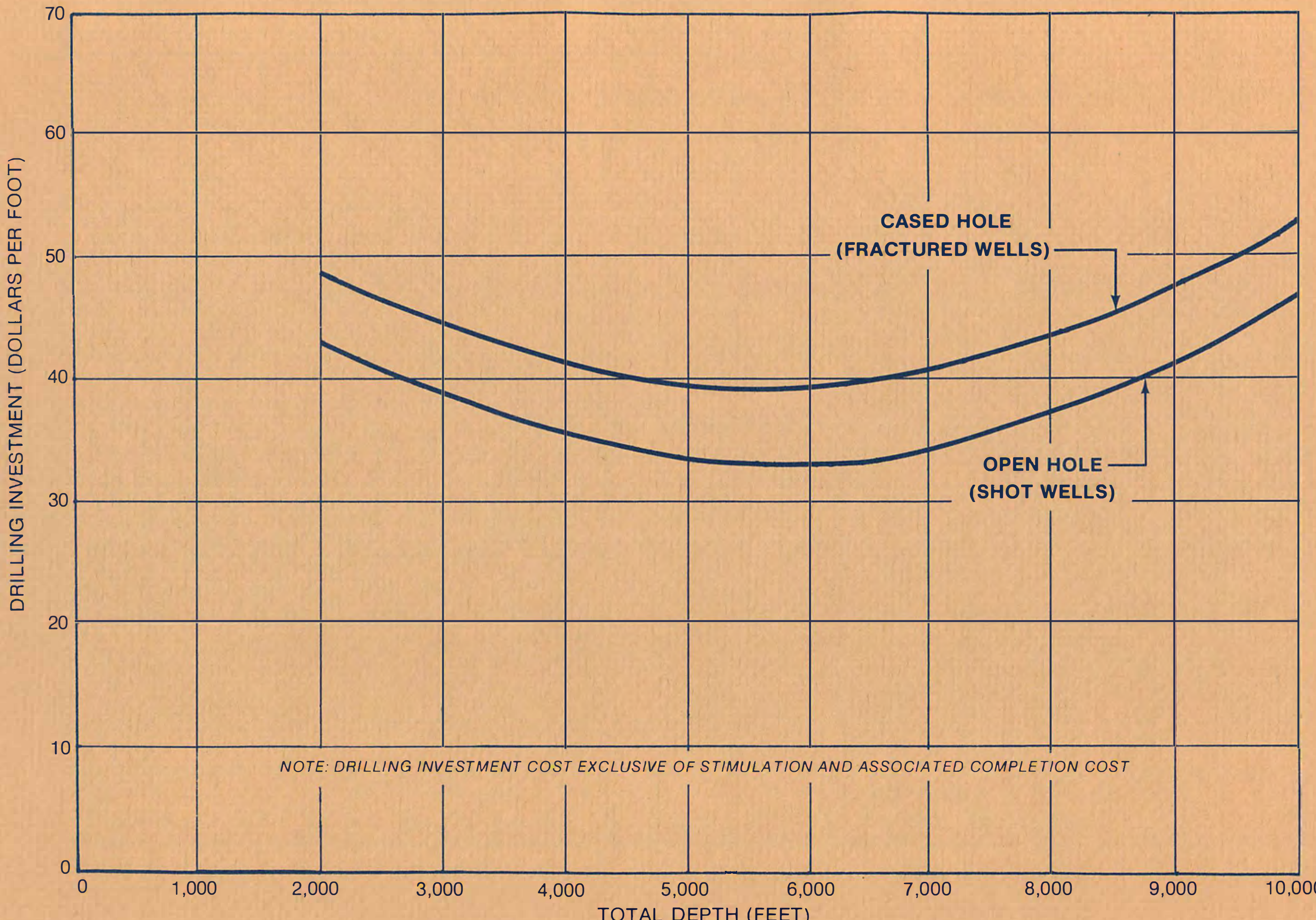

Figure 8. Well Drilling Investment (1979 Dollars)—Cost Per Foot vs. Total Depth.

Stimulation and Cleanup Cost

Current average costs were used for shot and conventionally fractured wells. For a shot well, the cost for a typical shot and subsequent cleanup is $15,000. For a typical conventionally fractured well (1,000 bbl gelled water, 50,000 lb sand), a cost of $35,000 was estimated, which includes perforating, stimulation, and cleanup costs. Advanced stimulation methods are expected to require more sophisticated technology, and in all likelihood will cost more than current methods. A range of stimulation costs from $50,000 to $100,000 was considered; a value of $75,000 was assumed for the base case. Although a portion of these costs could be due to higher cost exploration techniques, all of the costs were included under the stimulation cost category for simplicity.

Leasehold Cost

An average figure of $2,000 per well was estimated for capitalized lease cost. This includes acquisition costs and delay rentals and assumes historically derived 160-acre spacing.

Exploration Cost

An average figure of $6,000 per well was estimated for exploration cost. This includes geological, geophysical, and engineering activities on a per-well basis.

Dry Hole Cost

A Devonian Shale well generally must be stimulated and tested before it can be determined whether the well is a producer or a dry hole. The plugging and abandonment costs for a dry hole are typically offset by salvage values of recovered casing, etc. Dry hole costs are therefore lower than completed wells by the sum total of wellhead, valving, and tubing costs. On a per-foot basis, these costs are approximately $2.50 per foot. The drilling cost of a dry hole is therefore less than a producing well per the following formula:

Dry hole cost = producing well cost - ($2.50 per foot x total depth)

Success Ratio

An 88 percent success ratio was assumed. The ratio accounts for both technical (mechanical/economic) and geologic failures, which implies that 88 percent of the wells that are drilled and stimulated can be put on line, and will produce enough gas to warrant doing so. The 88 percent value is representative of the operational experience of several companies involved with Devonian Shale drilling. The average production expected from the wells that are put on line is estimated from the gamma-ray black shale thickness correlation discussed in the Extrapolation Rationale section of Chapter Three.

Well Line Cost

For the analysis, a 2,500-foot average line requirement per producing well was assumed based on 160-acre spacing at a cost of $10 per foot. That gives a total well line cost per producing well of $25,000.

Annual O&M Cost

Based on experience, an average operating and maintenance (O&M) cost of $1,500 per producing well per year was used. Since this is a direct operating cost, the direct cost overhead factor discussed in the Overhead section of this chapter was applied, making the total per-well cost $1,800 per year.

Royalty

The one-eighth royalty is prevalent throughout Devonian Shale producing areas and was used in this study.

Btu Content

The Btu content for shale wells is generally higher than the 1,000 Btu per cubic foot standard pricing reference. Values used in this study were: 1,150 Btu per cubic foot for Kentucky, Tennessee, West Virginia, and Virginia; 1,100 Btu per cubic foot for Ohio; and 1,050 Btu per cubic foot for Maryland, New York, and Pennsylvania. Therefore, in the economic analysis all gas volumes were adjusted so that the price was equivalent to 1,000 Btu per cubic foot of gas.

Overhead

The overhead parameters were consistent among the NPC's Unconventional Gas Sources Task Groups, which amounted to 10 percent of initial capital (factor 1.1) and 20 percent of direct operating expense (factor 1.2).

Taxes

For the sake of uniformity, identical tax rates were used by each of the Task Groups. These include:

- 46% federal income tax rate
- 2% state income tax rate
- 8% (of producer revenue) production, severance, and property tax
- 10% federal investment tax credit on tangible equipment.

For tax purposes, the source of funds was ignored. The most favorable tax treatment of investment and other costs was used in accordance with current tax regulations.

Intangible drilling costs were expensed in the year incurred, and tangible equipment costs were depreciated, using double declining balance with switchover to straight line later in the well life. An average value of 20 percent for the tangible portion of the investment was assumed with a 30-year tax life. Geological/geophysical exploration and leasehold acquisitions were capitalized and cost depleted.

Rate of Return (ROR)

Three after-tax ROR's (10, 15, and 20 percent) were investigated. The base case for production estimates is 10 percent, which projects proven economic viability for development of the Devonian Shale resource.

Gas Price

Five gas prices ($/MMBtu) were investigated -- $2.50, $3.50, $5.00, $7.00, and $9.00.

Compression Cost

With the large number of producers in the eastern United States, it is the exception rather than the rule for individual operators to acquire and drill large blocks of contiguous leaseholds. It is not economically feasible for the producer to install compressor facilities at each well or even a small group of wells. Historically, it has been the practice for the purchaser, usually the gas utility company, to own the field suction trunklines and compressor station facilities. The advantages of economy of scale are achieved in this mode of operation and permit the most efficient method for handling of field gas. The purchase contract between the seller (producer) and the buyer (gas utility) for the sale of well production is customarily made on a lease-by-lease basis. As an area develops, the utility extends the suction lines from their centralized compressor station facilities, and the producers tie into these gathering line extensions. Thus, the point of sale becomes the nearest distance to the utility's suction pipeline. Since the "downstream" costs are the burden of the purchaser, it was the opinion of the NPC that these costs should be considered separately in the economic analysis. Therefore, as a means of recognizing downstream gas processing as a cost function, a range of costs was determined on an after-tax basis, depending upon the cost of fuel. The assumptions and calculations are presented in Appendix E.

Well Life

The useful life of a gas well is highly variable and dependent upon many factors, which may be physical, economic, or a combination of circumstances. In this study, a producing well life of 30 years was chosen as representative for drilling investment decisions. Production beyond the 30-year period would have very little effect upon the economic results. However, it is acknowledged that the producing characteristics of the Devonian Shale formation may warrant a longer well life, which would result in ultimate reserves higher than those reserves stated based on the 30-year life. On the other hand, it is recognized that premature abandonment can occur, which makes the prediction of additional reserves beyond 30 years uncertain.

CHAPTER FIVE

POTENTIAL PRODUCTION AND RESERVES[1]

The determination of production potential and reserves for Devonian Shale requires the calculation of gas prices on a per-well basis for the various geographical subdivisions, estimation of the drillable area within those subdivisions, computation of the total potential "per-well" reserves, and development of production and reserves addition profiles for various drilling schemes. In this chapter the components of these various analyses are discussed in detail. The chapter has been divided into four major sections. The first section describes the gas price analysis, the second discusses the rationale used to determine drillable area, the third presents the results of the potential reserves analysis, and the fourth discusses the potential production analysis (drilling scenarios).

GAS PRICE ANALYSIS

Description of the Discounted Cash Flow (DCF) Model

Under the guidelines for the overall unconventional gas study, the price of gas is determined on the basis of a discounted cash flow (DCF) analysis for a base case of a 10 percent rate of return (ROR) and two other cases based on 15 and 20 percent ROR.

The DCF method is commonly used by industry to compare commercial ventures, determine price structure, and estimate financial requirements. It is generally not the method used by federal and state regulatory bodies to determine price. The DCF method offers a number of advantages:

- The time value of money is considered.
- The returns do not need to be scaled to project size.
- The calculations are independent of any assumption about project financing or corporate capital structure.

[1]Based on Appalachian basin data, and results apply to only that area.

The form of the DCF equation utilized for the Devonian Shale analysis is:

$$- D_o - E_o - W_o u + \sum_{t=1}^{n} \frac{u[PQ(t) - O\&M(t) - L(t) - D(t) - E(t)]}{(1 + r)^{t-\frac{1}{2}}}$$

$$+ \sum_{t=1}^{n} \frac{D(t) + E(t)}{(1 + r)^{t-\frac{1}{2}}} + \frac{CD_o}{1 + r} = 0 \qquad \text{(Eq. 3)}$$

where

P = gas price

$Q(t)$ = estimated production for year t

$Q_o = \sum_{t=1}^{n} Q(t)$

$O\&M(t)$ = operating and maintenance expenses for year t

$L(t)$ = lease or royalty expenses for year t

D_o = tangible costs that must be depreciated

E_o = intangible costs that must be cost depleted

W_o = intangible well costs that can be expensed

$D(t)$ = depreciated value of tangible costs in year t; initially double declining balance with later switchover to straight line when advantageous

$$E(t) = \frac{Q(t)\left[E_o - \sum_{t'=1}^{t-1} E(t')\right]}{Q_o - \sum_{t'=1}^{t-1} Q(t')} \qquad \text{(Eq. 4)}$$

u = income tax retention rate or (1 - effective tax rate)

C = equipment investment tax credit rate

r = discounted cash flow rate of return (DCF ROR)

t = time index in years

n = lifetime of project

The timing sequence for the discounting of the cash flows is based on midyear convention. In the economic analysis, single well investment is assumed to begin at middle of the year, or $t = -1/2$. Commencement of production occurs at the end of the year, $t = 0$, with annual incomes and disbursements as lump-sum payments at midyear; i.e., $t = 1/2$, $t = 1\ 1/2$, etc.

Economic and Production Parameters

The Coordinating Subcommittee of the National Petroleum Council's Committee on Unconventional Gas Sources provided a baseline of economic parameters for use in determining gas prices for this study. The basis for analysis is January 1, 1979, dollars, which remain constant for the project lifetime. Royalties were to be typical for each area. For the Devonian Shale regions this would be a one-eighth (12.5 percent) royalty. The tax rates assumed for the study, as discussed in Chapter Four, are:

- 46% federal income tax rate
- 2% state income tax rate
- 8% (of producer revenue) production, severance, and property tax rate
- 10% federal investment tax credit on tangible equipment.

No depletion allowance is assumed for Devonian Shale wells. Overhead is assumed to be 10 percent of the invested capital and 20 percent of direct operating cost. Working capital for well drilling is normally small and was assumed to be zero. It was further assumed that the leasehold and exploration costs (E_o) are subject to cost depletion.

The total investment cost for each well is calculated from the following relationships:

$$W = (C_D \times D + S_t + LE) \qquad \text{(Eq. 5)}$$

$$WT = OH \times \left[W + \frac{1 - R}{R}(W - 2.5 \times D) + G\right] \qquad \text{(Eq. 6)}$$

where

W = raw well cost

WT = total well investment cost; 20 percent is tangible cost (capitalized), 80 percent is intangible cost (expensed and cost depleted)

= $D_o + W_o + E_o$ in Equation 3

C_D = drilling cost per unit depth on a per-county basis

D = average depth (to the bottom of the shale) in the county

S_t = stimulation cost

= \$35,000 for current hydraulic fracturing (conventional fracturing technology)

= \$15,000 - \$6 x average shale thickness in the county (traditional shooting technology)

LE = initial lease and exploration costs (\$8,000)

OH = overhead factor (1.1 for 10 percent overhead)

R = success ratio (0.88 is the fraction of total Devonian Shale wells drilled that are productive)

G = per-well gathering line cost (\$25,000)

The addend $\frac{1 - R}{R}$ (w - 2.50 x D) in the total investment cost is an allocation of the dry hole costs to the producing wells. The 2.50 is the net dollar salvage value per foot for a dry hole. The capitalized costs are depreciated initially on a double declining balance basis with switchover to straight line basis when advantageous.

As was discussed earlier, the production of gas from Devonian Shale can be described by a hyperbolic decline curve with C_1 varying, $C_2 = 3$, and $C_3 = 2.5$, leaving the simplified form

$$PR = C_1 \left[1 + \frac{5}{6} t\right]^{-\frac{2}{5}} \qquad \text{(Eq. 7)}$$

where PR is the production rate in MCF/D and t is time in years.

Gas Price Analysis Results

The basic subdivision unit for the gas price analysis of the Appalachian basin is the county. Drilling depth, black shale log thickness, and drilling cost were obtained on a county-by-county basis to provide the cost data for the analyses. A representative investment cost for each county was calculated using Equation 6, using an average depth and an average cost per unit depth for the county. The gamma-ray log black shale average thickness (T) for each county was used to calculate corresponding C_1 values for the traditional completion technique (shooting). The gas prices were calculated using the computed C_1 values to determine annual production. Three prices were calculated corresponding to ROR's of

10, 15, and 20 percent. Table 8 presents some example results. For various counties, the table shows C_1 values, the corresponding average well investment costs used in the gas price calculations, and resultant gas prices at the three respective ROR's.

TABLE 8

Example Price Calculations for Selected Counties

County Average C_1	County Average Well Investment	Price per MMBtu at Rate of Return 10%	15%	20%
74	264,900	2.60	3.44	4.28
79	224,400	2.09	2.76	3.42
65	185,200	2.12	2.80	3.47
59	145,800	1.91	2.50	3.09
10	139,700	10.62	13.91	17.18
45	246,200	3.95	5.23	6.50
8	125,900	12.86	16.80	20.71
73	191,500	1.94	2.55	3.17
97	230,900	1.73	2.29	2.84
63	163,900	1.97	2.59	3.21

DETERMINATION OF DRILLABLE AREA AND WELL SPACING

The basis for the resource estimate included all lands underlain by Devonian Shale. However, from a practical standpoint, it could not be assumed that the entire area can be drilled due to certain factors. Land use restrictions in the eastern United States must be taken into account in determining the total drillable area. These restrictions include certain state and federal lands where drilling is prohibited. Also, it is reasonable to assume that urban areas, existing storage fields, and developed shale-producing fields should not be considered potential leasehold areas. Therefore, the above-mentioned categories were excluded from the area resource to arrive at the potential drillable area. Based on actual experience, two other steps were required in determining the drillable areas. Not all potential lands can be leased, due to landowners' refusal to lease, coal mining difficulties, etc. Of the lands that are leased, there are those properties which cannot be drilled due to such problems as mineral titles, right-of-way access, leaseholds committed to existing drilling, etc.

The following model was used to calculate the net drillable areas:

Resource Total Area, less
physical barriers
certain government lands
storage fields
producing shale areas
others

= potential lease lands, less
nonleasable areas

= leasable properties, less
nondrillable areas

= Net Drillable Areas

Since the above factors used in determining the drillable areas are not constant for the total area considered, calculations were made essentially on a county-by-county basis. The drillable area calculations for the Appalachian basin are presented in Appendix F.

The following tabulation is a summary by state of the Appalachian net drillable areas:

	Net Drillable Area (Square Miles)
Kentucky	7,282
Maryland	711
New York	12,273
Ohio	10,616
Pennsylvania	15,020
Tennessee	1,309
Virginia	1,280
West Virginia	13,701
Rounded Total	62,000

It is recognized that there is no single best spacing in which wells can be uniformly drilled throughout the basin. Well spacing practices vary from one locality to another, depending upon geologic heterogeneity, production performance, and operators' preferences and past experiences. The consensus of the study participants was that 160 acres per productive well would be a reasonable average well spacing throughout the basin. The net producible area is the net drillable area reduced by 5 percent (62,000 sq mi to 58,900 sq mi) to account for geologic failures as discussed in the Success Ratio subsection found later in this chapter.

POTENTIAL RESERVES ANALYSIS

Methodology

Given the gas price and producible reserves per well for a county and the drillable area in the county, a table of potential reserves available at various prices for both traditional and conventional technology can be constructed. The number of wells that can be drilled in a county was determined on the basis of an assumed 160-acre spacing. Algebraically this is represented as:

$$\text{County Reserves} = \text{per well reserves} \times \text{county producible area} \div 160 \qquad \text{(Eq. 8)}$$

Results of Base Case Analysis

For purposes of tabulation and comparison, the potential county reserves were grouped on the basis of price and production technology. Table 9 summarizes the results of the base case analysis. Two rows of data are presented corresponding to reserves calculated for traditional and conventional technologies. Under the column headed 2.50 are listed the reserves in TCF, calculated to sell at a price (based on a 10 percent ROR) of $2.50 per MMBtu or less. Under the column headed 3.50 are the reserves calculated to sell at less than $3.50 (including those selling under $2.50) and so forth. Under the column headed Total Producible Gas are listed the reserves that can be recovered at any price, and under the column headed Average Price are the average prices for each technology if all of the reserves are produced.

TABLE 9

Results of the Base Case Reserves Analysis
(10 Percent ROR)
(Constant 1979 Dollars)

Technology	Cumulative Potential Reserves (TCF) vs. Price ($/MMBtu) 2.50	3.50	5.00	7.00	9.00	Total Producible Gas	Average Price
Traditional	3.3	8.5	11.4	14.9	16.6	25.3	8.57
Conventional	7.3	14.5	19.5	23.5	27.0	37.4	6.75

Sensitivity Analysis (Based on Conventional Technology)

While the base case presents the results for the combination of parameters believed by the NPC to be most representative of the resource, the effect of changes to key parameters were studied to determine the sensitivity of the base results to those parameters. Parameters examined consist of ROR, C_1, and success ratio.

Rate of Return (ROR)

The ROR is an important parameter in economic analysis. It reflects both the degree of risk inherent in the technology, and the marketplace and the general economic environment in which the resource development must operate. For the purpose of this study two ROR's, 15 and 20 percent, were examined in addition to the base case. The results for conventional fracturing technology are summarized in Table 10.

TABLE 10

Rate of Return Sensitivity
(Constant 1979 Dollars)

Rate of Return	Cumulative Potential Reserves (TCF) vs. Price ($/MMBtu) 2.50	3.50	5.00	7.00	9.00	Total Producible Gas	Average Price
10%*	7.3	14.5	19.5	23.5	27.0	37.4	6.75
15%	2.8	8.6	15.2	19.9	23.0	37.4	8.98
20%	0.3	4.6	11.1	16.7	20.6	37.4	11.18

*Denotes the base results.

Hyperbolic Decline (C_1)

As discussed earlier, C_1 is computed as a function of gamma-ray log black shale thickness (T), expressed mathematically as $C_1 = f(T)$. The linear coefficient relating C_1 to thickness is nominally 0.213; the 95 percent confidence interval ranges from 0.184 to 0.241. Table 11 summarizes the effects of computation over this range, based on conventional technology.

TABLE 11

Hyperbolic $C_1 = f(T)$ Linear Coefficient Sensitivity
(Constant 1979 Dollars)

Linear Coefficient	Cumulative Potential Reserves (TCF) vs. Price ($/MMBtu) 2.50	3.50	5.00	7.00	9.00	Total Producible Gas	Average Price
0.184	5.2	11.2	15.0	19.0	21.6	33.1	7.63
0.213*	7.3	14.5	19.5	23.5	27.0	37.4	6.75
0.241	10.1	16.6	22.7	26.2	31.0	41.2	6.13

*Denotes the base results.

Success Ratio

Success ratio in this analysis is a measure of both technical (mechanical/economic) and geologic failures based on Devonian Shale drilling experience. For purposes of comparison, additional success ratio values were used to compute reserve distribution as summarized in Table 12. Because the level for technical (mechanical/economic) failure (7 percent) is subject to little variation in future drilling operations, the success ratio sensitivity in Table 12 is based solely on shifts in percentage of geologic failures of zero, 5 (base case), 10, and 20 percent. Again the sensitivities are based on conventional technology.

TABLE 12

Success Ratio Sensitivity
(Constant 1979 Dollars)

Success Ratio	Cumulative Potential Reserves (TCF) vs. Price ($/MMBtu) 2.50	3.50	5.00	7.00	9.00	Total Producible Gas	Average Price
0.93	9.0	15.8	20.9	24.8	28.9	39.4	6.45
0.88*	7.3	14.5	19.5	23.5	27.0	37.4	6.75
0.83	6.1	13.6	16.6	21.5	24.8	35.4	7.09
0.73	4.0	9.4	14.0	17.8	20.1	31.5	7.89

*Denotes the base results.

POTENTIAL PRODUCTION ANALYSIS

Introduction

The production of gas and development of reserves as a function of time is dependent on the marketplace, the ability of industry to develop the resource, and regulatory and other federal and state policies. For the purpose of this analysis, it was assumed that a market exists for gas produced at a price based on a 10 percent ROR. Further, it was assumed that a favorable regulatory and policy environment would exist for natural gas production.

The ability of industry to develop the resource is therefore the controlling factor, and this was assumed to depend primarily on the availability of drilling rigs and trained crews. An analysis of recent rig availability data for the Appalachian region was made, and the results extrapolated to the year 2000. The total number of wells drilled per year was estimated, based on the available rigs and the reserve additions calculated on the basis of the cheapest gas being drilled first.

Methodology

The methodology for Devonian Shale gas production estimates consisted of first determining the total amount of producible gas at each specified price level (i.e., $2.50, $3.50, $5.00, $7.00, and $9.00 per MMBtu) for current and advanced technology, and then using appropriate drilling scenarios (drilling schedules) to drill and produce the producible areas beginning with the cheapest gas and continuing with increasingly more expensive gas. Production estimates consisted of annual production, cumulative production, drilled reserves added annually, cumulative drilled reserves added, and reserves remaining. Drilled reserves added annually are defined as the predicted 30-year production for wells drilled in a given year, and reserves remaining are defined as cumulative drilled reserves added minus cumulative production.

Availability of Drilling Rigs

The potential for production from Devonian Shale through the end of this century is a function of capacity to drill wells in addition to demonstrated economic viability and environmental acceptability of possible extraction methods. To provide a data base for estimation of possible drilling scenarios (drilling schedules), the Hughes' rig count (reported in the Oil & Gas Journal) was plotted from 1973 through early 1979 for the entire United States (Figure 9) in order to estimate the industry's ability to furnish new rigs and crews. During this six-year period, the number of available rigs increased at an average rate of 195 rigs per year. A similar plot was made of the rig activity in the Appalachian area for the same period (Figure 10), which showed an average increase of seven rigs per year, but with sporadic year-to-year fluctuations. In particular, Appalachian rig activity between 1975 and 1978 showed a growth rate of 15 rigs per year.

Accordingly, it was assumed that 15 rigs drilling Devonian Shale in 1980, with 15 additional rigs devoted to shale drilling each succeeding year through 2000, represents an accelerated or high-level drilling scenario. Under this sort of progression, 330 rigs would be actively drilling Devonian Shale wells by year-end 2000.

As a second, more moderate scenario, 12 rigs were assumed to be drilling the shale in 1980, with a 12 percent increase in rigs each succeeding year. Under this schedule, 129 rigs would be involved by year-end 2000. The 12 percent increase per year is similar to that indicated from 1973 to 1979 in the Appalachian area.

World Oil forecasts a gain of 291 rigs in the United States for 1979.[2] This is a 50 percent increase over the 195 rigs per year additions evidenced for the 1973-1979 period. It therefore appears that the accelerated drilling scenario is within the nation's ability to produce rig and drilling crew additions.

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[2] World Oil, Feb. 15, 1979.

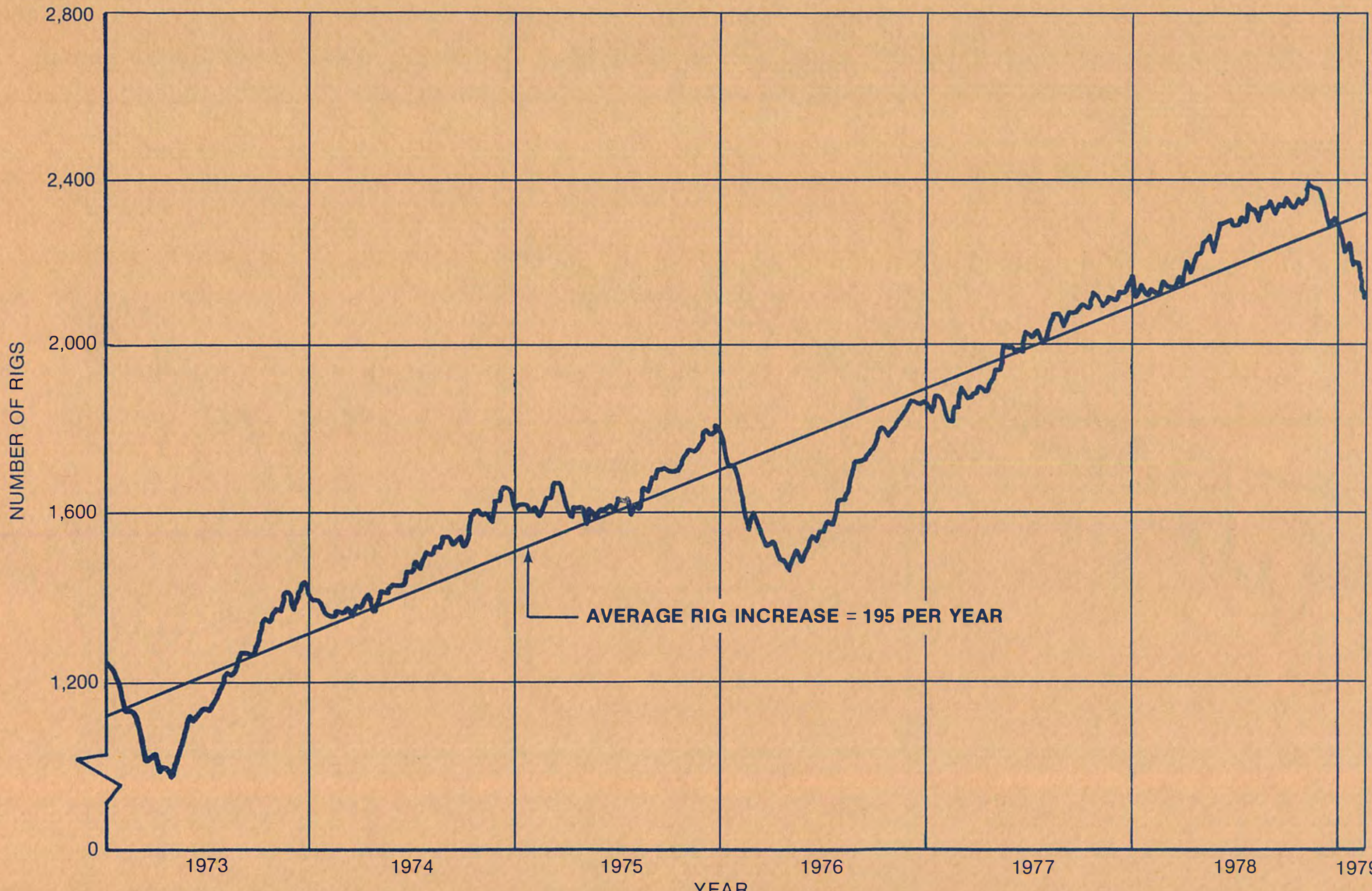

Figure 9. Hughes Rig Count for U.S. Total (1973-1979).

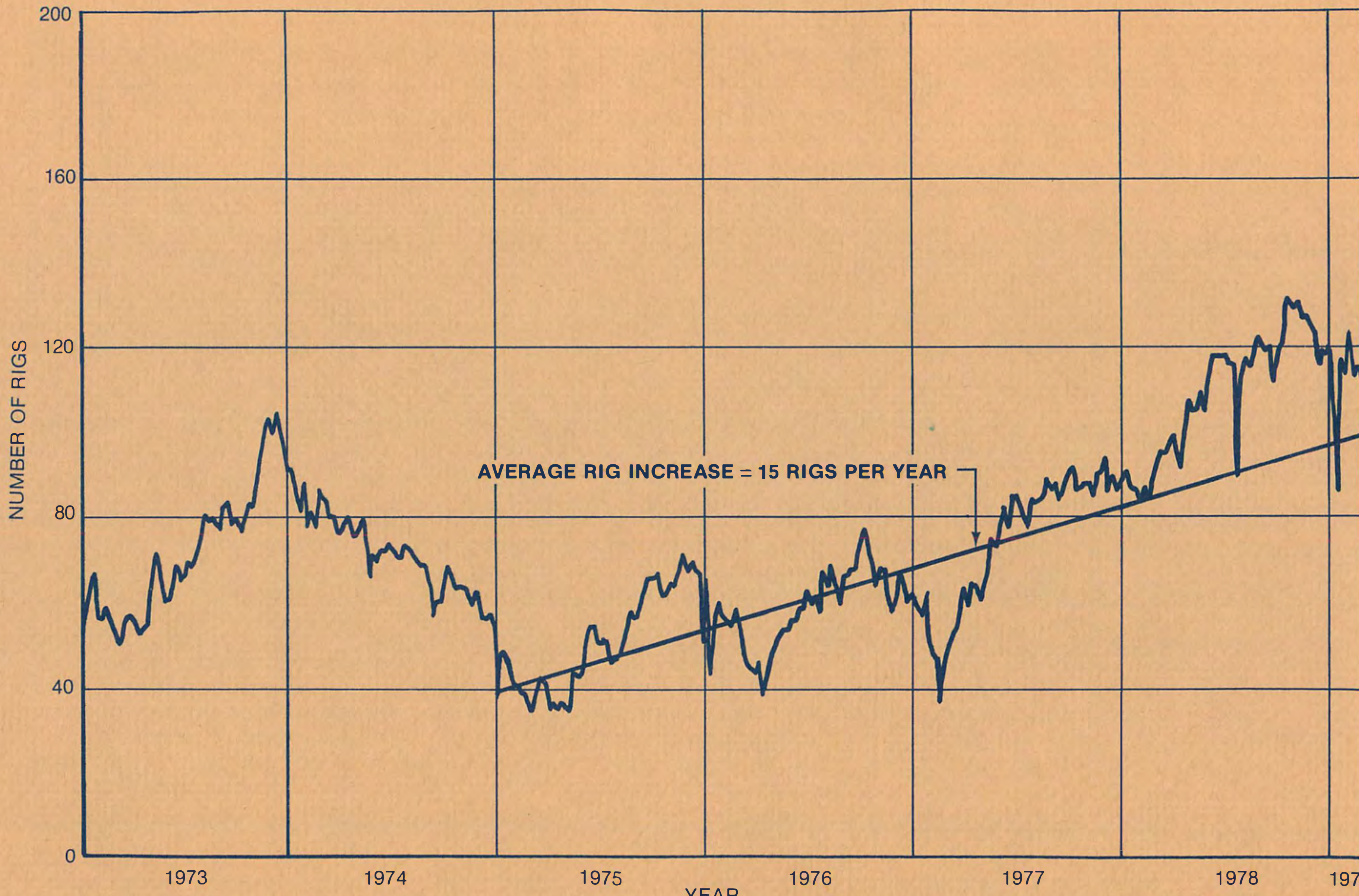

Figure 10. Hughes Rig Count for Appalachian Area (1973-1979).

Drilling Scenarios

Based on the above analysis, two drilling scenarios were developed. The low growth or moderate case assumes starting with 12 rigs drilling Devonian Shale wells at the beginning of 1980 and growing at a 12 percent rate per year to the year 2000. The second, higher growth scenario assumes starting with 15 rigs and adding 15 rigs per year to the year 2000. All rigs were assumed to drill 35 productive wells per year.

Results of the Scenario Analysis

Figures 11 and 12 summarize the results of the production and reserve analyses for the low and high growth scenarios for the conventional technology case. Shown are the annual rates of wells added, production, and reserves added as a function of time. Figures 13 and 14 show the integrated results for total wells, cumulative production, and drilled reserves remaining as a function of time (drilled reserves remaining = cumulative reserves added - cumulative production).

As can be seen from Figures 11 and 13, the low growth (moderate) scenario provides a limited incremental or total production over the time period to the year 2000. Figures 12 and 14, for the high growth (accelerated) scenario, show the potential production increasing to a level of 1 TCF annually, with a cumulative production of 11 TCF by the year 2000. The magnitude of the drilling effort to accomplish this production level requires the development of essentially all the potential reserves priced up to and including \$9.00 gas over the next 20 years.

Appendix G gives the computer printout of the production economics. There are six data sets for each technology, based on the two levels of drilling activity (low rig growth and high rig growth) and ROR's of 10, 15, and 20 percent. Annual projections through the year 2000 for the traditional technology begin on Page G-1 and end on G-33. Similar data for the conventional technology appear on Pages G-34 through G-66.

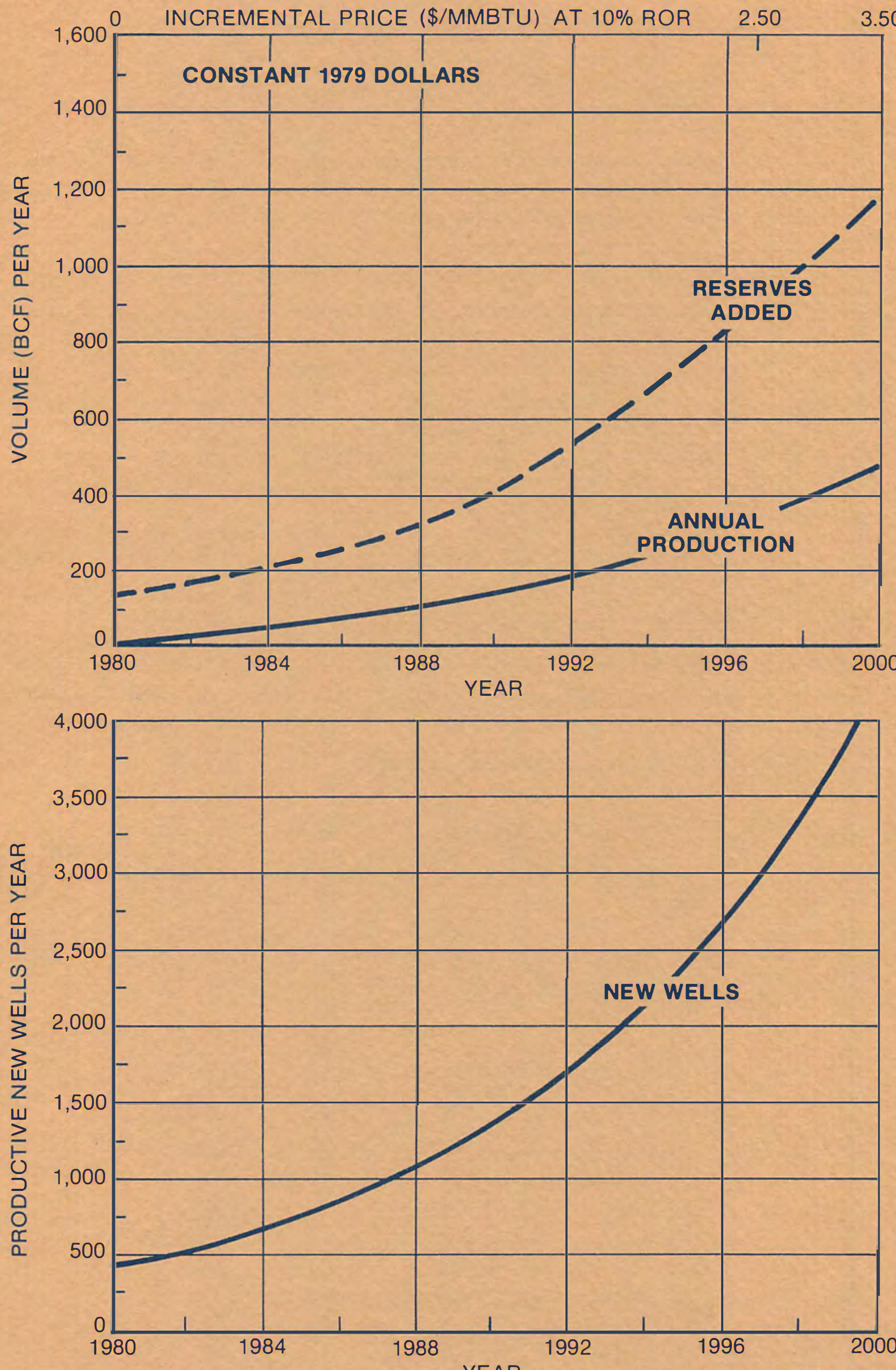

Figure 11. Annual Rates as a Function of Time.
Conventional Technology—Low Growth Scenario.

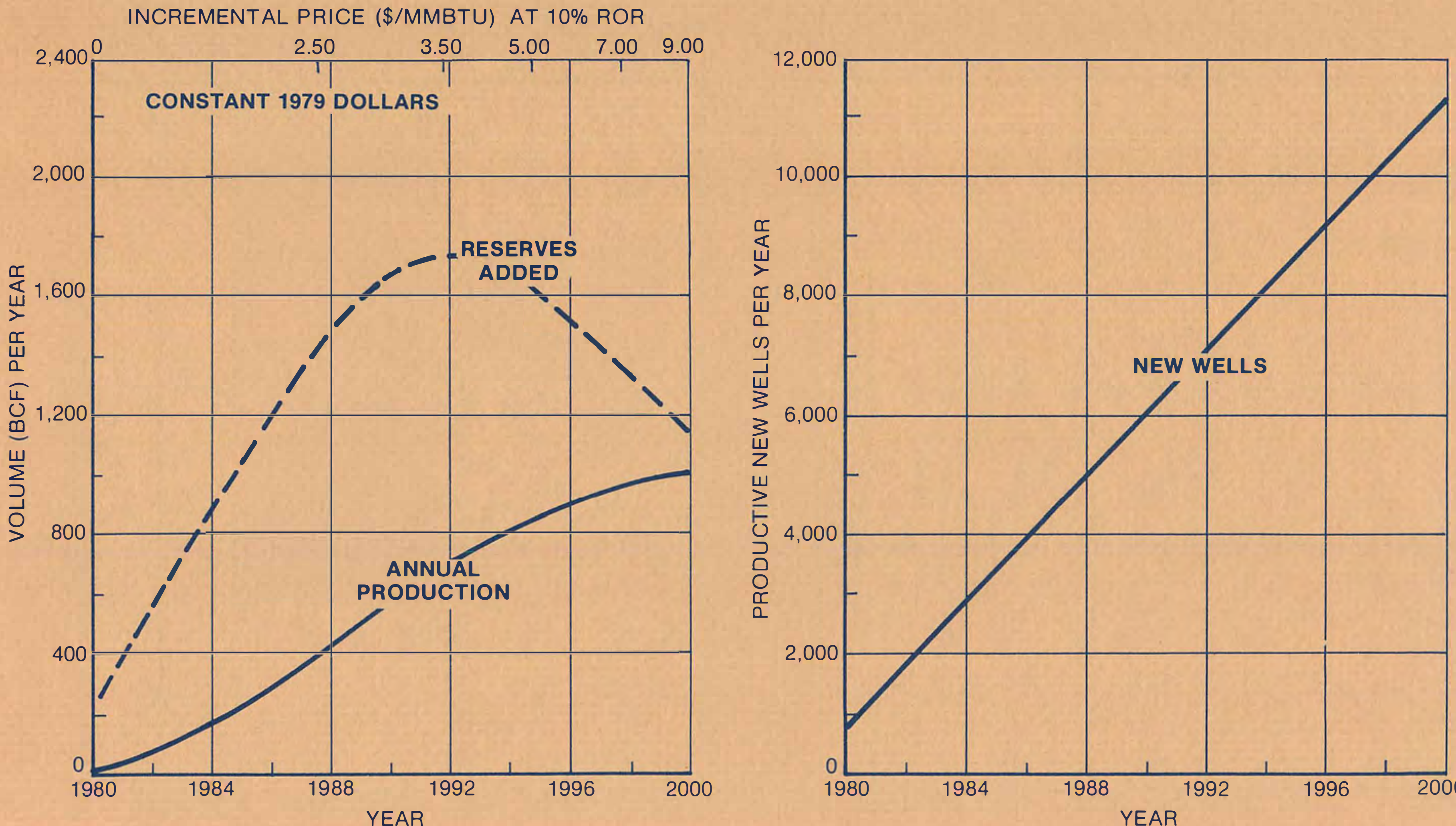

Figure 12. Annual Rates as a Function of Time. Conventional Technology—High Growth Scenario.

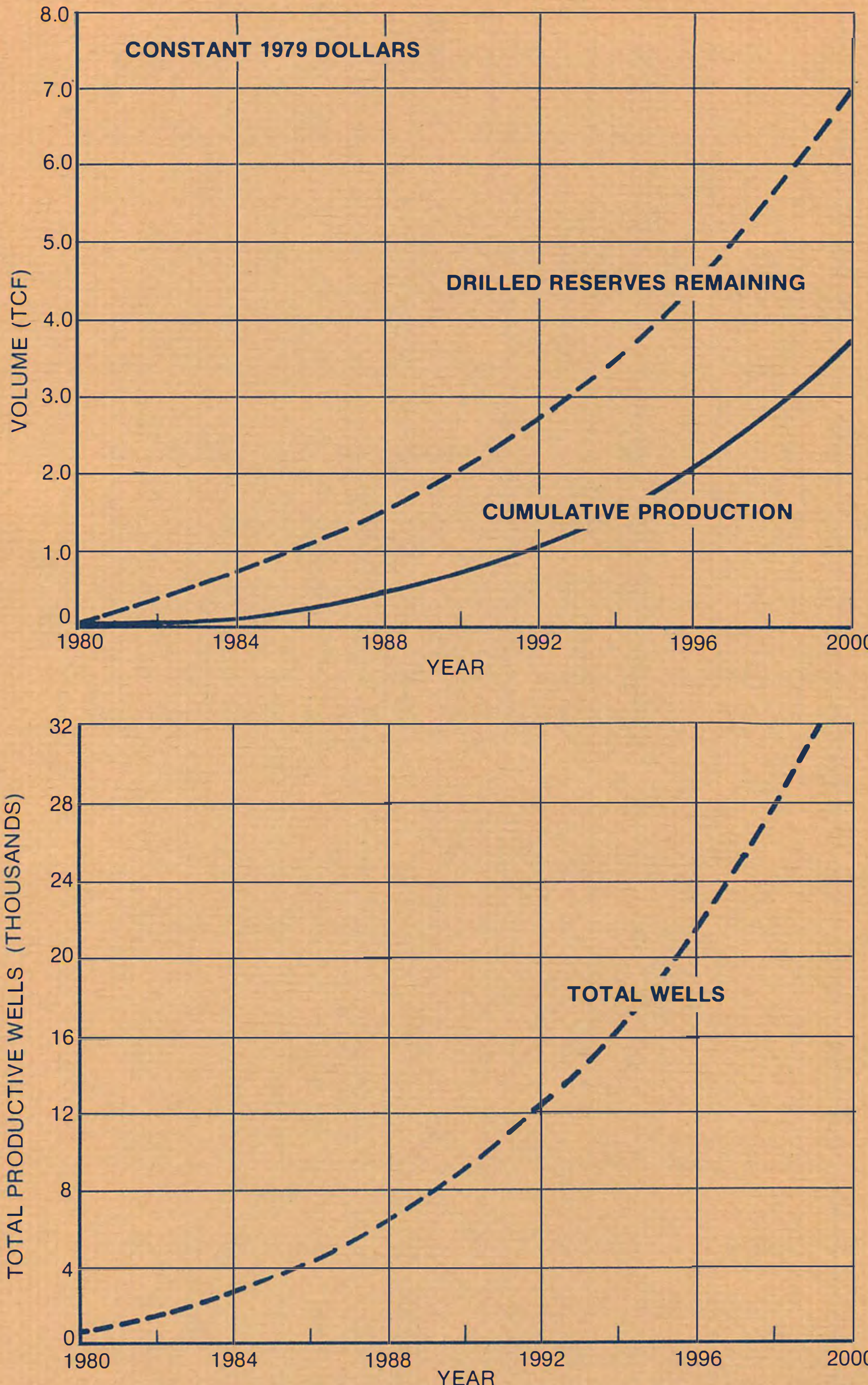

Figure 13. Total Wells, Production, and Reserves Remaining as a Function of Time. Conventional Technology—Low Growth Scenario.

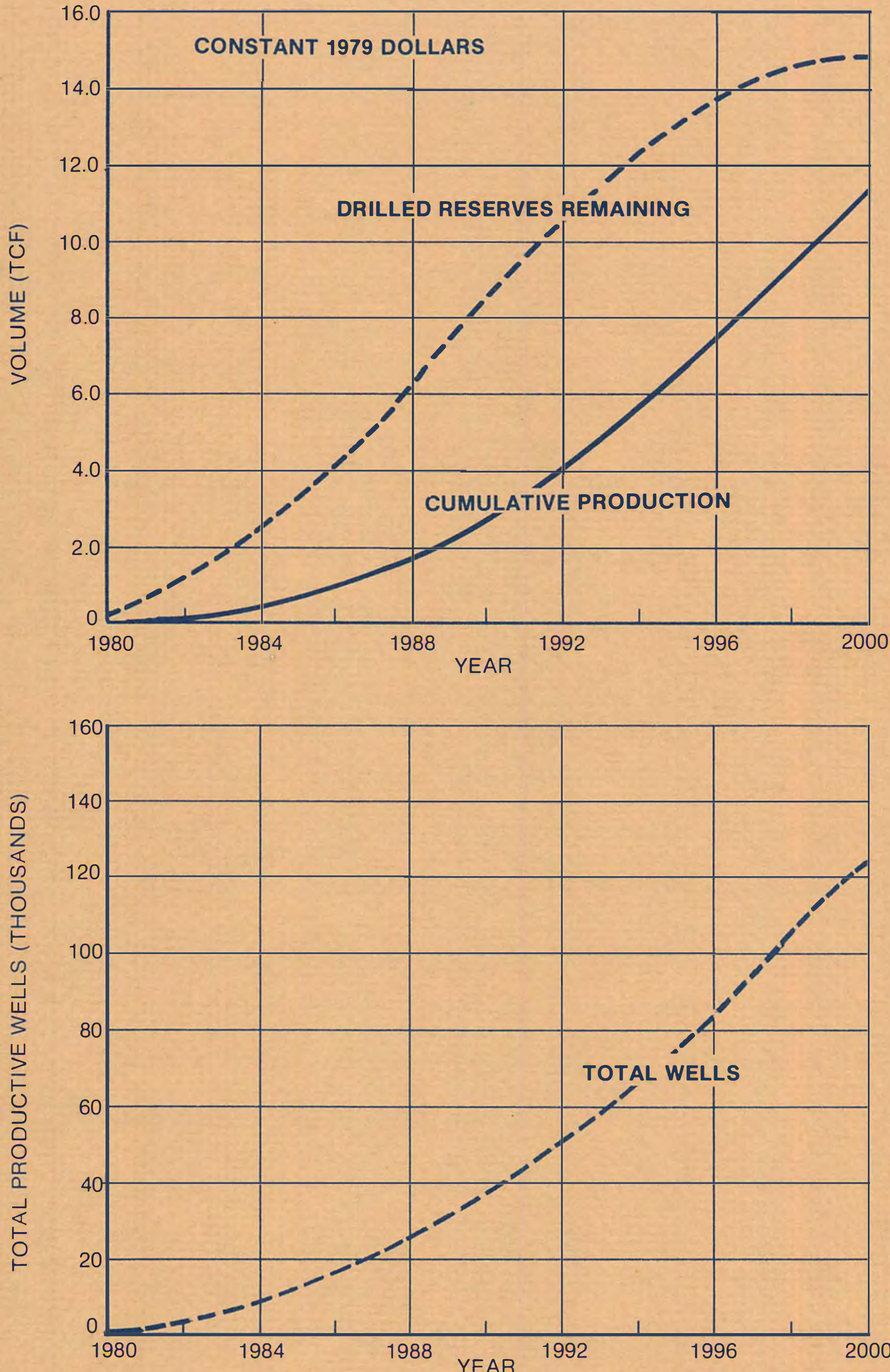

Figure 14. Total Wells, Production, and Reserves Remaining as a Function of Time. Conventional Technology—High Growth Scenario.

CHAPTER SIX

ADVANCED PRODUCTION TECHNOLOGY[1]

RATIONALE

Stimulation Techniques

Although considerable data exist (Chapter Five) which demonstrate the advantages of well bore shooting and conventional fracturing techniques on Devonian Shale gas production, exact reservoir production mechanisms are not well understood. Many questions exist today as to which stimulation methods give the best performance in a given producing area and the optimum treatment specifications for a particular method. Research efforts (ongoing and planned) by industry and such organizations as the DOE Eastern Gas Shales Project and the Gas Research Institute will hopefully provide answers to these questions in the near term (i.e., five to ten years). The ultimate goal is to optimize treatment designs for specific applications, and to demonstrate the best possible production economics and reserve additions per well. Potential cost-effective advanced stimulation techniques under investigation include massive hydraulic fracturing, foam fracturing, gas fracturing, explosive fracturing, and novel applications such as dendritic fracturing and deviated hole fracturing.

Exploration Techniques

Perhaps as important as advances in stimulation research are advances in exploration techniques for Devonian Shale. Remote sensing techniques, depositional reconstruction interpretation, and other advanced geological and geophysical approaches have the potential for defining the areas having the better natural fractured shale before any drilling investment is made. Improved logging tools, coring techniques, and interpretation can better define the best intervals to be stimulated within the shale formations. Finally, better understanding of the production characteristics and other properties of the shale can be achieved by advances in well testing and interpretation. Accurate modeling of shale gas production derived from test data interpretation may eventually lead to optimization of stimulation techniques in specified areas of interest.

Advanced Technology Projections

Potential contributions to advanced technology, such as optimized well stimulation methods and more reliable exploration techniques, could improve shale productivity. A limited amount of

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[1]Based on Appalachian basin data, and results apply to only that area.

advanced technology test data exist today which indicate that conventional technology productivity can be increased as shown in Figure 15.

Examples of available advanced technology data include three wells stimulated with new technology in a developed shale area of Kanawha County, West Virginia. Two wells in this area were stimulated using a "gas frac" treatment, which utilized a fluid combination of methanol, propanol, and carbon dioxide. The third well was shot with liquid explosives. The average production levels resulting from these wells are summarized in Table 13, along with average production data from five traditional shot wells in the same area. Comparable data are also presented in Table 14 for a set of five conventionally fractured wells in the same area. The average increase over traditional shooting for the three advanced technology wells is 230 percent, compared to an average increase of 80 percent for the five conventionally fractured wells. The treatments used in the advanced technology wells resulted in a substantial increase of production over that achieved by the conventionally fractured wells. Based on these observations, it was assumed for this study that advanced technology would double the improvement of conventional technology over traditional technology (Figure 15).

ULTIMATE RESERVES ANALYSIS

Based on the assumption that advanced technologies will double the improvement of conventional technology over traditional technology, three different advanced technology cases were examined. The three cases assume, respectively, $50,000, $75,000, and $100,000 costs for the per-well stimulation costs, as opposed to the $35,000 assumed for conventional technology. The results are tabulated in Table 15 along with the results for the conventional and traditional technology from Chapter Five.

Examining these results and comparing them with the results in Chapter Five, it is apparent that two significant benefits are derived from the development of advanced technology. The first is a 33 percent increase in the total producible gas (37.4 TCF to 49.9 TCF), and the second is a significant shift downward in the average price of producible gas.

Figure 16 illustrates the price and the aggregate of potential reserves that may possibly be developed by traditional technology, conventional technology, and the $75,000 advanced technology, assuming 10 percent ROR.

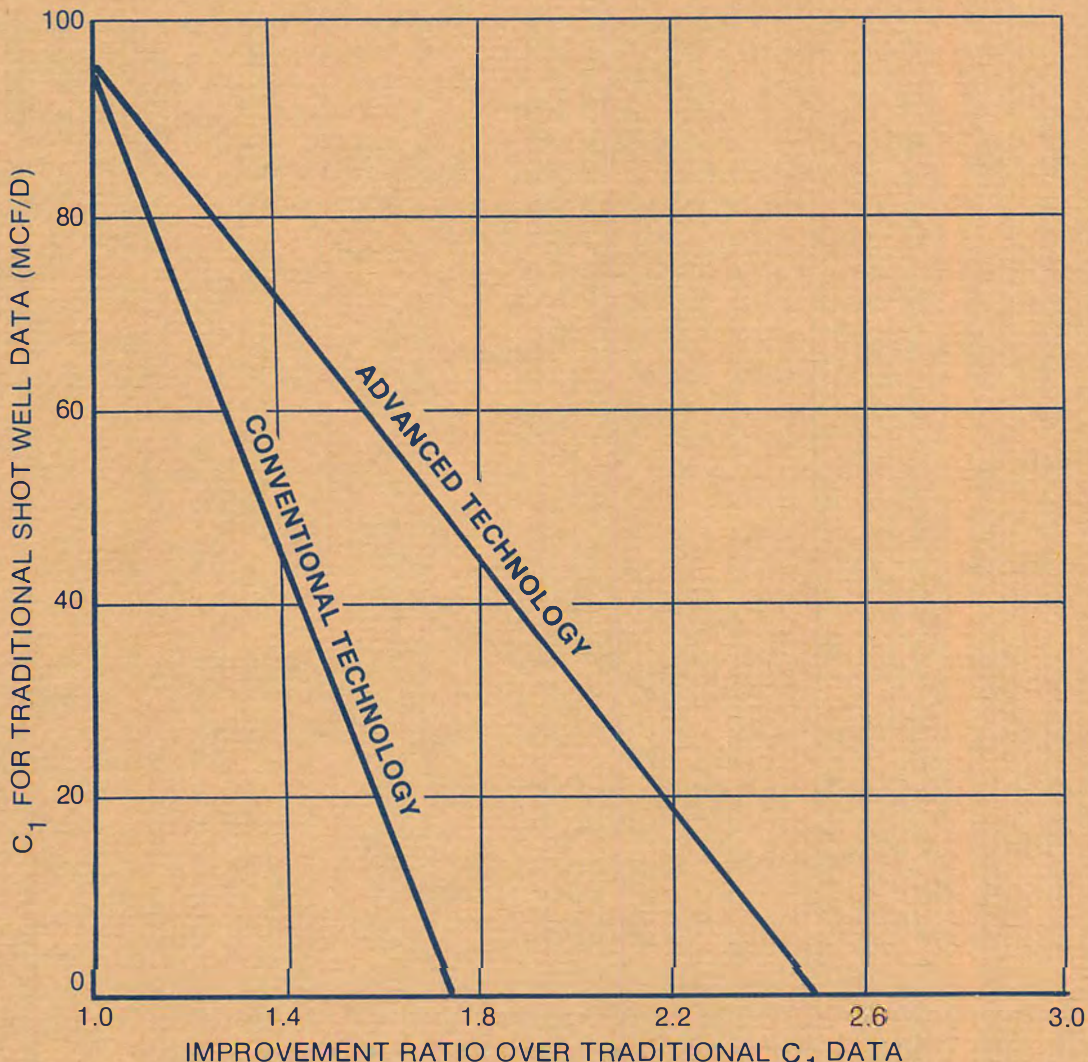

Figure 15. Improvement Ratios for Current and Advanced Technology Relative to Traditional Shot Well C_1 Data.

TABLE 13

Advanced Technology Increase Over Traditional Technology
Kanawha County, West Virginia

Year	Traditional Shot Data for 5 Wells, Average Well Open Flow = 229 MCF/D: Annual Production Average per Well (MMCF)	Traditional Shot Data for 5 Wells, Average Well Open Flow = 229 MCF/D: Best Fit $C_1 = 33$ (MMCF)	Advanced Technology Data for 3 Wells, Average Well Open Flow = 400 MCF/D: Annual Production Average per Well (MMCF)	Advanced Technology Data for 3 Wells, Average Well Open Flow = 400 MCF/D: Best Fit $C_1 = 111$ (MMCF)
1	11.1	10.6	35.6	35.6
2	8.8	8.7	30.2	29.5
3	7.3	7.7	26.5	25.9
4	6.5	7.0	24.2	23.6
5	5.8	6.6	23.7	22.2
Cumulative	39.5	40.6	140.2	136.8

$$C_1 \text{ increase} = \left(\frac{\text{advanced technology}}{\text{shooting}}\right) = \frac{111}{33} = 3.3$$

TABLE 14

Conventional Fracturing Increase Over Traditional Technology
Kanawha County, West Virginia

Year	Traditional Shot Data for 5 Wells, Average Well Open Flow = 229 MCF/D: Annual Production Average per Well (MMCF)	Best Fit $C_1 = 33$ (MMCF)	Conventional Technology Data for 5 Wells, Average Well Open Flow = 174 MCF/D: Annual Production Average per Well (MMCF)	Best Fit $C_1 = 60$ (MMCF)
1	11.1	10.6	19.5	19.2
2	8.8	8.7	16.0	16.0
3	7.3	7.7	13.7	14.0
4	6.5	7.0	12.6	12.7
5	5.8	6.6	11.8	12.0
Cumulative	39.5	40.6	73.6	73.9

$$C_1 \text{ increase} = \left(\frac{\text{conventional fracturing}}{\text{shooting}}\right) = \frac{60}{33} = 1.8$$

TABLE 15

Reserves Analysis Results of Advanced Technology
Compared with Conventional and Traditional Technologies
(10 Percent ROR)
(Constant 1979 Dollars)

Technology	Cumulative Potential Reserves (TCF) vs. Price ($/MMBtu)					Total Producible Gas	Average Price
	2.50	3.50	5.00	7.00	9.00		
Advanced ($100,000)	7.6	18.3	26.2	30.9	38.0	49.9	6.25
Advanced ($75,000)	11.8	20.1	27.2	32.9	38.9	49.9	5.79
Advanced ($50,000)	13.1	21.2	29.1	35.9	41.8	49.9	5.33
Conventional	7.3	14.5	19.5	23.5	27.0	37.4	6.75
Traditional	3.3	8.5	11.4	14.9	16.6	25.3	8.57

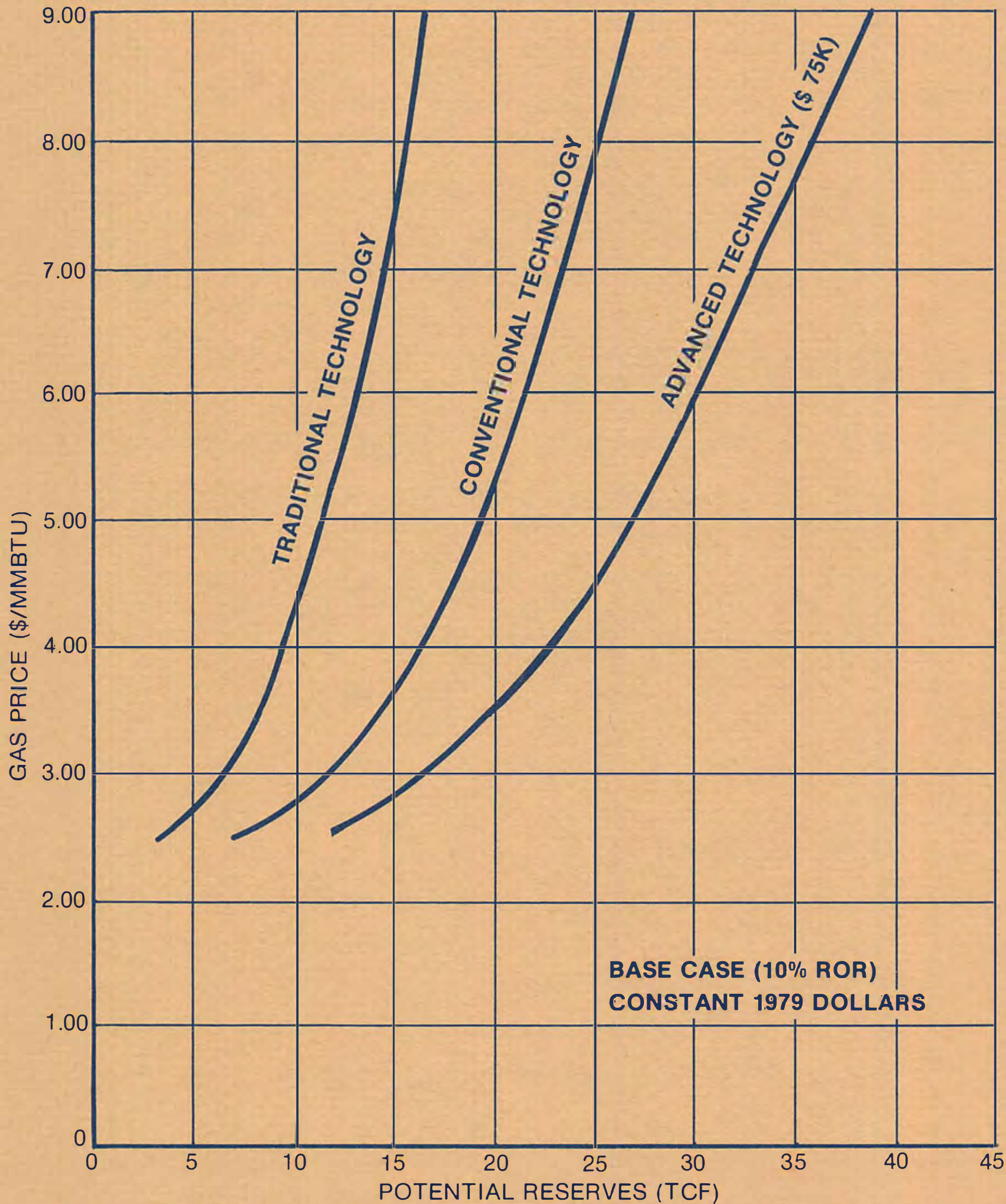

Figure 16. Gas Price as a Function of Potential Reserves for Various Technology Levels.

POTENTIAL PRODUCTION AND RESERVES ANALYSIS

The effect of advanced technology on production and the development of drilled reserves was calculated for the high growth scenario discussed in the Drilling Scenarios subsection of Chapter Five. It was assumed that conventional technology would be utilized until the price of advanced technology production could match that of conventional technology. At that time a transition would be initiated. For purposes of this analysis it was assumed that the transition would occur uniformly over five years (i.e., 20 percent advanced technology wells the first year, 40 percent the second, increasing to 100 percent in the fifth year). The advanced technology data presented in Figures 17 and 18 were derived for the case with a stimulation cost of $75,000. Crossover from conventional to advanced technology occurs at a price of $1.91 per MMBtu after drilling 7,500 conventional technology wells. Examination of the results and comparison with the base case show a significant increase in both annual rate and reserves for the advanced case.

The computer printout of the production economics for advanced technology (without crossover from conventional technology) is provided in Appendix G. There are six data sets of annual projections through the year 2000, based on the two drilling scenarios (low rig growth and high rig growth) and ROR's of 10, 15, and 20 percent. These data appear on Pages G-67 through G-99.

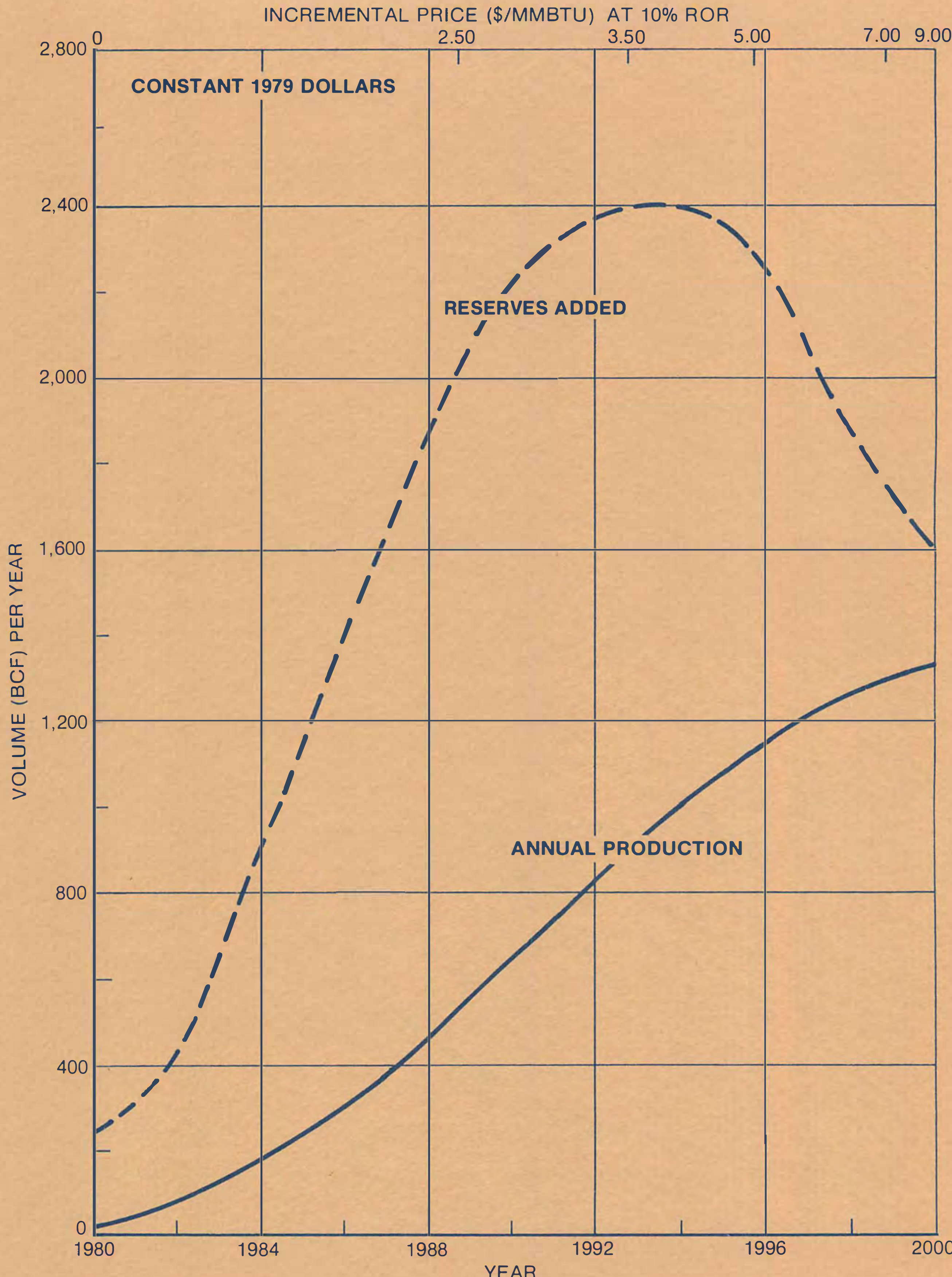

Figure 17. Rates of Production and Reserves Addition as a Function of Time. Advanced Technology with $75,000 Stimulation Cost—High Growth Scenario.

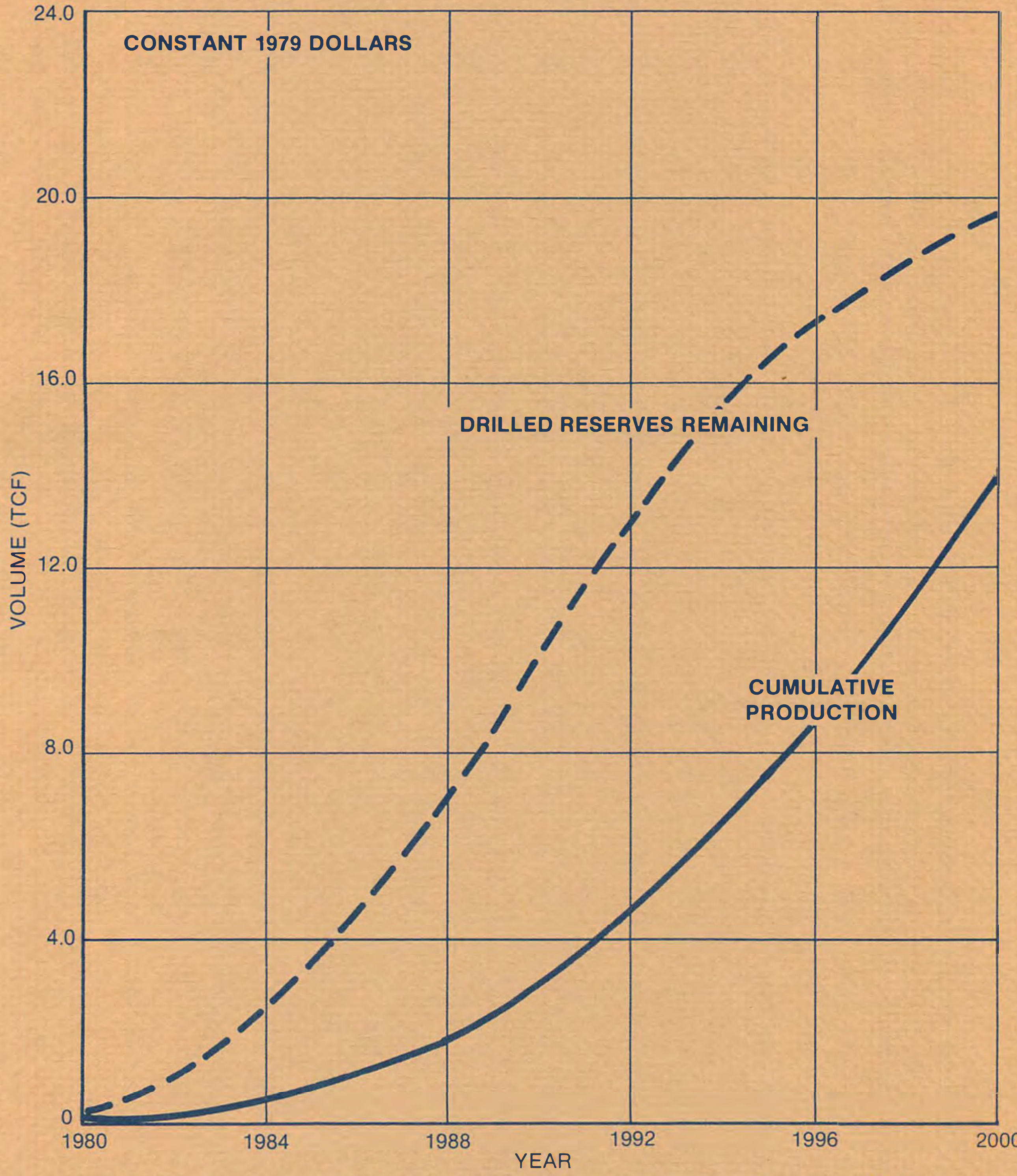

Figure 18. Total Production and Reserves Remaining as a Function of Time. Advanced Technology with $75,000 Stimulation Cost—High Growth Scenario.

CHAPTER SEVEN

CONSTRAINTS

SHORT-TERM CONSTRAINTS

The results of Chapter Five indicate between 3 and 7 TCF of Devonian Shale gas available at less than $2.50 per MMBtu for the base case. An obvious question is "Why isn't the gas being produced at a high rate of production?" The answer to that question is that a variety of short-term constraints exist as barriers to early increased production. A primary reason might be that of logistics:

- A significant portion of the $2.50 gas is located in or near the Big Sandy field which is already leased, and future development is subject to demand which will dictate when the gas will be produced, irrespective of price.

- In other areas of $2.50 Devonian Shale gas, there are probably no available pipelines.

Other important constraints consist of both economic and technical factors.

Economic Constraints

Inadequate Incentive

The 10 percent ROR value assumed in this report is representative of low-risk production from known or semi-proved formations: the 10 percent value is believed to be representative of Devonian Shale upon achievement of low-risk status, which comes from drilling sufficient numbers of wells in the unproven areas. However, a higher ROR than 10 percent is normally required for drilling unknown areas, which tends to increase the price of gas produced.

Price/Market Uncertainty

The price structure for natural gas based on the Natural Gas Policy Act (NGPA) definitions for pricing are subject to legal interpretations for Devonian Shale, which at this time are uncertain. In addition, field prices for natural gas are suppressed as a result of the current oversupply status (i.e., so-called gas bubble).

Lag Between Price Increase and Development

The overall natural gas price increases allowed by the NGPA (for which Devonian Shale sources qualify) have been in effect for less than one year. That is not sufficient time between price increases (and full understanding thereof) for production buildup.

Competition with Conventional Sources

Production of Devonian Shale gas in the Appalachian basin must compete with the more conventional sandstone formations which have achieved a higher degree of "proven" status. Producers are naturally inclined to produce their best proven sources first.

Technical Constraints

Uncertainty as to Best Stimulation Treatment

As discussed in Chapters Five and Six, increased Devonian Shale production can be achieved through a variety of improved well stimulation techniques, none of which today are well proven.

Uncertainty as to Which Zones to Stimulate

During gas well drilling operations, various logging tools are used to identify potential producing zones to be stimulated. In Devonian Shale formations, considerable ambiguity often results from standard log interpretations.

Demonstration of Technically Recoverable Gas from Nondrilled Areas

As stated in Chapter Three, much of the Devonian Shale resource is not only unproven, but undrilled. This results in considerable uncertainty as to the amount of technically recoverable gas.

ENVIRONMENTAL AND SOCIOECONOMIC CONSTRAINTS

Environmental constraints associated with Devonian Shale gas production are summarized below:

- Surface and ground water contamination during drilling and stimulation treatment operations
- Disruption of surface land due to construction and site preparation
- Ecologic disruption due to development operations
- EPA and local government regulatory constraints.

Frequently, environmental factors cause delays and increased costs. Those outlined above, however, are normally dealt with in the context of Devonian Shale drilling operations and numerous other ways, with attendant costs taken into account. There may be some delays derived from these causes, but they are not expected to constitute significant barriers to gas production.

Socioeconomic considerations related to major development of Devonian Shale resources are primarily beneficial, in that the region is economically depressed and needs an influx of monies and job opportunities. There may be, however, some temporary constraints in obtaining personnel appropriately trained for some of the more specialized occupations.

Under the high growth scenario, by the end of 1985 there would be 105 rigs operating in Appalachia on a full-time basis. Twelve thousand five hundred new wells would be in place, requiring approximately 250 workers for well servicing alone. In 1985, $68 million would be spent for service company stimulation treatments using current technology. By year-end 2000, there would be 330 rigs operating, 126,000 wells in place, and $225 million spent per year on stimulation services. This would result in thousands of direct jobs and many more indirect jobs related to Devonian Shale development.

LEGAL CONSTRAINTS

Potential legal constraints relative to Devonian Shale gas production involve land use and ownership rights. Prior to initiation of development activities, property ownership must be established, purchase or lease agreements arranged, and royalty payments determined. Often property titles are not readily available, difficult to trace, or not up to date.

Lease rates paid by lessees for gas ownership rights vary considerably throughout Devonian Shale producing regions, and in some instances unusually high royalty and/or bonus payment situations occur. Current experience would indicate, however, that these problems are ultimately resolved in reasonable time periods and, therefore, legal constraints are not expected to be significant barriers to production.

DRILLABLE ACREAGE AVAILABILITY

Of the total Devonian Shale potentially available for gas well production, only a portion may be considered drillable. The drillable acreage available on a county-by-county basis varies from a low of about 30 percent to a high of about 90 percent, with an overall average of about 56 percent.

Several factors contribute to nondrillable acreage, such as:

- Physical barriers due to urban centers, lakes and waterways, etc. (inaccessible topography was not taken into account)
- Gas storage fields and restricted use of government-owned lands
- Unavailable existing leaseholds
    - Devonian Shale depleted producing areas not subject to infill drilling

- Lessees not inclined to drill shale wells due to other commitments

- Unavailable lands due to owners' refusal to lease

- Lands for which leaseholds are subject to bad title, mineral disputes, lessor problems, etc.

Although some of these factors can possibly be overcome by successful negotiations with reluctant landowners and lessees, the large extent of nondrillable acreage represents a significant constraint to ultimate Devonian Shale gas recovery.

DRILL RIG AVAILABILITY

Realization of significant levels of Devonian Shale enhanced gas production from 1980 through 2000 will require drilling large numbers of wells annually. For example, a drilling scenario which forecasts 15 rigs initially in operation (at 35 wells/rig/year) and a 15-rig annual growth rate results in a total of 126,000 wells. Although the projected requirement for 330 rigs by the year 2000 is by no means insignificant, and competition for new rigs and trained crews among developing resources will play an important role in rig availability, the overall rig requirement for Devonian Shale will not tax the domestic capacity for new rig production. It has been estimated that an overall rig buildup rate between 7 and 10 percent per year can be sustained over the 1980 decade (Wiley, 1977). Thus, drill rig availability does not appear to be a serious constraint.

INVESTMENT LEVEL

As we have seen, significant gas production from Devonian Shale will depend on large exploratory and production drilling programs. This in turn requires a large investment level for capitalization. Under the high growth current technology scenario, $141 million would be invested in 1980, $622 million in 1985, $1.5 billion in 1990, and $2.4 billion in 1995. Through the year 2000 a total of $30.9 billion would have been invested in Devonian Shale wells. In addition: in 1985, $16.4 million would be spent on well servicing; in 1990, $56.4 million; in 1995, $120 million; and in 2000, $207.3 million. The latter funding would be from income, but the money market is the likely source of the investment capital. If the 10 percent ROR used in the analysis is competitive, the requirement for $31 billion over 20 years would not be a constraint. If the Appalachian basin continues to attract rigs, as indicated by recent history, there will be no drilling constraint; however, an overall examination of competition for rigs for conventional and unconventional resources throughout the United States is needed to determine if historical trends are realistic predictors of the future.

CHAPTER EIGHT

COMPARISON WITH OTHER STUDIES

There have been a number of studies conducted recently on the potential of gas recovery from Devonian Shale. In this section, the NPC findings are compared with the Office of Technology Assessment report and the Lewin report.

DESCRIPTION OF OTHER REPORTS

Office of Technology Assessment (OTA) Report[1]

OTA Results

The major results and conclusions of the OTA report are summarized below:

- The Devonian Shale resource can be developed without significant increases in technology.
- Readily recoverable reserves (defined as recoverable reserves over a 15-20 year development period) from 15 to 25 TCF are possible at gas prices of $2.00 to $3.00 per MCF (1976 dollars).
- Ultimate recoverable reserves (to economic limit, from 30 to 50 years) from 23 to 38 TCF are possible at gas prices of $2.00 to $3.00 per MCF (1976 dollars).
- Annual production of 1 TCF can be achieved after a 20-year development period, at gas prices of $2.00 to $3.00 per MCF (1976 dollars).

OTA Methodology

- Representative samples of existing shale production were broken down into subgroups by quality. These samples contained predominantly shot wells, although fractured wells were also included. Fifteen- and 20-year production histories were averaged for these subgroups.
- The economics of the subgroups were determined using a DCF approach at a 10 percent ROR.
- It was assumed that 10 percent of the undeveloped Devonian Shale area of the Appalachian basin could be commercially

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[1]Status Report on the Gas Potential from Devonian Shales of the Appalachian Basin, Office of Technology Assessment, Congress of the United States, Nov. 1977.

developed at a gas price of $2.00 to $3.00 per MCF. This was based on production history, shale depth, shale thickness, fractures, and drilling experience.

- Using economical 15-year and 20-year reserves in the $2.00-$3.00 price range from the existing data and applying these to 10 percent of undeveloped acreage, a range of readily recoverable reserves from 15 to 25 TCF was calculated. An average well spacing of 150 acres was assumed.

- Based on existing production decline curves, ultimate recoverable reserves from 23 to 38 TCF were calculated over an additional 10 to 30 years of production.

- Based on pipeline availability and the extensive amount of drilling necessary to generate the above reserves, it was estimated that it would take 20 years to obtain an annual production of 1 TCF from this resource.

Lewin Report[2]

Lewin Results

- With no federal/industry research and development (R&D), ultimate recoverable reserves (30-year reserves) from 2 to 10 TCF will be developed over the next 30 years by industry, at gas prices from $1.75 to $4.50 per MCF (1977 dollars).

- With federal/industry R&D, ultimate recoverable reserves from 4 to 25 TCF can be developed over the next 30 years, at gas prices from $1.75 to $4.50 per MCF (1977 dollars).

- With no federal/industry R&D, and at current prices, annual production can be expected to remain at current levels over the next 20 years, or approximately 0.1 TCF.

- With federal/industry R&D and a $3.00 per MCF gas price, annual production could rise to 0.6 TCF in 10 years, and level off to 0.5 TCF in 20 years.

Lewin Methodology

- The purpose of the Lewin study was to estimate 30-year production data for those areas where sufficient data were available on the resource to make preliminary estimates of the economic potential. The 210,000 square miles in the Appalachian basin were analyzed as summarized in Table 16.

[2] Enhanced Recovery of Unconventional Gas, Vols. I-III, Lewin and Assoc., Inc.; Feb. 1978 (Vols. I & II), Jan. 1979 (Vol. III).

TABLE 16

Analysis of the Appalachian Basin

Definition of the Area	Area (Square Miles)	%	Scope of Study Undertaken
Unproductive	100,000	48	Excluded because geology indicated the shale is thin, absent, or the likelihood of gas is low.
Speculative	48,000	23	Insufficient data are available to define the economic potential of the area. Hence, excluded from this study.
Proved/Developed or Found Dry	5,000	2	Gas potential already included in proved reserves or past production.
Probable/Possible	57,000	27	Included in the study as the potential source of additional gas.
Total	210,000	100	

- The 57,000 square miles that form the basis for the Lewin study were divided into areas having common geologic characteristics or drilling and production histories.

- Average well productivity in each area was then extrapolated based on historical data from over 250 wells. Only wells for which individual production data were available for a significant number of years were included. To reflect that drilling on the average is concentrated in the better areas, and that the production data tended to be from the better wells, playout factors were applied for subsections of each area. Factors reflecting productivity increases due to current technology (hydraulic fracturing) were then applied to the shot well production data.

- The economics of each subarea were determined using DCF's and a 15 percent ROR. Total economic 30-year reserves were then determined at different gas prices by aggregating the economic reserves for each subarea (base case).

- Technology improvements due to federal/industry R&D were estimated, and the economic reserves were calculated under these scenarios and a 10 percent ROR (advanced case).

- Annual production to the year 2000 was predicted for the base and advanced cases. The drilling model assumes that:

  - For probable acreage, base case drilling commences immediately and is concluded within 17 years. Advanced case drilling starts three years later but is completed within 13 years.

  - For possible acreage, base case drilling is lagged nine years and is completed within 17 years. To model the combined effects of resource characterization and improved technology, drilling is lagged nine years but is completed within 15 years under the advanced case.

COMPARISON OF NPC REPORT WITH OTHER REPORTS

Comparison of Results

Comparisons of the major findings of the NPC report with those of the other Devonian Shale assessment reports are given in Table 17. (The price references in the NPC column are adjusted to a 1,000 Btu per cubic foot heating value.) As observed in the table, the NPC recoverable reserves and annual production results agree closely with the Lewin results, while the OTA results are more optimistic. The NPC report was the only one to give a resource estimate, so no comparisons can be made in that category.

It should be noted that the reports reflect costs and prices in different constant year dollars. The OTA report is in 1976 dollars, the Lewin report is in 1977 dollars, and the NPC report is in 1979 dollars. If the NPC report were based on 1976 or 1977 dollars, the prices would have been lower. In addition to differences in the calendar year costs, there were also differences in other economic parameters. One example of these differences is the 10 and 15 percent ROR's used by Lewin for their estimates, compared to 10 percent for the OTA estimate, and 10, 15, and 20 percent for the NPC estimates. Because of the differences in economic inputs, any comparison of results between these reports should take those differences into account.

Comparison of Methodology in NPC and Other Reports

Resource Assessment

Since the NPC made the only resource assessment of the three reports, no comparison can be made. However, a resource estimate in the three eastern Devonian Shale basins was made by DOE in

1977.[3] This estimate ranged from 234 to 1,157 TCF in the Appalachian basin. The NPC estimate is higher than the DOE estimate primarily because of the inclusion of the gray or organic-lean shales in the resource base, whereas the DOE report considered only the black or organic-rich shales. However, the black shale estimates are comparable.

Potentially Producible Areas

The OTA derived a 16,300-square mile producible area on the assumption that 10 percent of the total Appalachian basin would be economical to produce at a price of $2.00 to $3.00 per MCF. The potentially producible area was therefore considered to be of the same quality as currently producing areas which are economical at $2.00 to $3.00 per MCF.

Lewin eliminated areas which were assumed to be unproductive, speculative, proved, or dry. The remaining 56,700 square miles of potentially productive area were considered by Lewin to have the best production potential.

In the NPC study, areas were not excluded on a resource quality basis, but were eliminated by practical considerations. Some of the areas excluded are nondrillable urban areas, lakes, developed shale areas, storage fields, government restricted lands, and areas not available due to leasing considerations. The latter, by far, is the most important restriction to development, and most of the areas were eliminated because of leasing restrictions and related problems. The 62,000-square mile remaining area is not all higher quality shale, but reflects the parts of each area of the Appalachian basin that can be considered drillable on a practical basis.

Elimination of a high percentage of the higher quality areas for practical considerations is a major difference between the NPC study and earlier reports. Leasing considerations and other practical factors are major constraints to development of Devonian Shale.

Well Production Estimates

Existing well production data and extrapolation rationales used to estimate undrilled area production for different levels of technology were different in each report. The OTA well production estimates for drilled areas and for a certain percentage of undrilled areas were based on a sample comprised of shot and fractured well production, and no estimate of the production potential of new technology was made. Both Lewin and the NPC considered the base or current (conventional) technology case to be best represented by fractured well production. Both of these reports relied upon Ray's data to estimate fractured well decline curves.

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[3] Enhanced Gas Recovery Program -- Eastern Gas Shale Project -- Implementation Strategy, Morgantown Energy Technical Center, U.S. Department of Energy, Nov. 4, 1977.

Advanced technology was treated differently by each report. As mentioned above, the OTA did not consider advanced technology. Lewin assumed a lower ROR and a higher success ratio, as well as increased production, for the advanced case compared to the base case. Well costs, however, were assumed to be the same for both levels of technology. The NPC study assumed both increased production and increased costs for the advanced technology case, but with the same ROR and success ratio.

A major difference between the reports was the rationale used to extrapolate production to undrilled areas. The OTA simply assumed that a certain percentage of the undrilled area would be of the same quality as producing areas. Lewin assigned "playout" factors to production in undrilled areas, assuming that they would be of lower quality than currently producing areas. The NPC investigated several variables thought to be associated with production, and found a correlation between existing shale production and black shale thickness as determined from gamma-ray logs. These log thicknesses were obtained throughout the Appalachian basin, and production in undrilled areas was estimated on the basis of the correlation.

Ultimate Recoverable Reserve Estimates

The economic approach for all three studies was the same. A DCF analysis (net present value) was used to determine the economic areas within the potentially producible areas at various ROR's and gas prices. Based on the estimated production and well spacing assumed for each area, the recoverable reserves were estimated at each gas price. Although the basic economic approach was the same for all the studies, different economic inputs were used in each report.

Annual Production Estimates Over the Next 20 Years

The OTA did not develop a drilling model, but assumed an average annual production of 1 TCF by the year 2000, based on their 15- to 20-year recoverable reserve estimate of 15 to 25 TCF. They estimated that 69,000 wells would be required to develop this production in 20 years. Lewin used a drilling model as described in Volume III of their report. The NPC annual production estimates were based on two drilling scenarios, as previously discussed. The more conservative estimates were based on a scenario which results in 36,000 producing wells being drilled through the year 2000. The more liberal estimates assume that 126,000 producing wells will be drilled over that same period.

TABLE 17

Major Results of NPC and Other Devonian Shale Studies
Appalachian Basin

	NPC*	OTA†	Lewin§
A. Gas In Place Resource	225-1,861 TCF	--	--
B. Potentially Producible Area	58,900 sq mi¶	16,300 sq mi	56,700 sq mi
C. Recoverable Resource @ Gas Price ($/MCF) and ROR (%)			
1. Current Technology§§	@ 2.50-5.00/MCF 7-19 TCF (ROR=10) 3-15 TCF (ROR=15) 0.3-11 TCF (ROR=20) @ 5.00-9.00/MCF 19-27 TCF (ROR=10) 15-23 TCF (ROR=15) 11-21 TCF (ROR=20)	@ 2.00-3.00/MCF 15-25 TCF (ROR=10)	@ 1.75-4.50/MCF 2-10 TCF (ROR=15)
2. Advanced Technology	@ 2.50-5.00/MCF 12-27 TCF (ROR=10) 3-21 TCF (ROR=15) 0-17 TCF (ROR=20) @ 5.00-9.00/MCF 27-35 TCF (ROR=10) 21-32 TCF (ROR=15) 17-29 TCF (ROR=20)	@ 2.00-3.00/MCF 30-35 TCF (ROR=10)	@ 1.75-4.50/MCF 4-25 TCF (ROR=10)

TABLE 17 (continued)

	NPC*	OTA†	Lewin§
D. Cumulative Production to Year 2000 @ Gas Price ($/MCF) and ROR (%)**			
1. Current Technology§§	@ 2.50-5.00/MCF 3-9 TCF (ROR=10) 2-8 TCF (ROR=15) 0.2-7 TCF (ROR=20) @ 5.00-9.00/MCF 9-11 TCF (ROR=10) 8-11 TCF (ROR=15) 7-10 TCF (ROR=20)		@ 1.75-3.00/MCF 1-4 TCF (ROR=15)
2. Advanced Technology	@ 2.50-5.00/MCF 4-13 TCF (ROR=10) 2-11 TCF (ROR=15) 0-10 TCF (ROR=20) @ 5.00-9.00/MCF 13-15 TCF (ROR=10) 11-14 TCF (ROR=15) 10-14 TCF (ROR=20)		@ 1.75-3.00/MCF 3-10 TCF (ROR=10)

TABLE 17 (continued)

	NPC*	OTA†	Lewin§
E. Maximum Annual Production to Year 2000 @ Gas Price ($/MCF)††			
1. Current Technology§§	@ 2.50-5.00/MCF 0.3-0.9 TCF	@ 2.00-3.00/MCF 1.0 TCF	@ 1.75-4.50/MCF 0.1-0.4 TCF
	@ 5.00-9.00/MCF 0.9-1.0 TCF		
2. Advanced Technology	@ 2.50-5.00/MCF 0.5-1.2 TCF	@ 2.00-3.00/MCF 1.5-2.0 TCF	@ 1.75-4.50/MCF 0.2-0.9 TCF
	@ 5.00-9.00/MCF 1.2-1.4 TCF		

*Based on constant 1979 dollars.

†Based on constant 1976 dollars.

§Based on constant 1977 dollars.

¶Total drillable area of 62,000 sq mi reduced by 5 percent to account for geologic failures.

**Cumulative production for NPC figures based on high-growth drilling scenario.

††Maximum annual production for NPC figures based on high-growth drilling scenario.

§§For the current technology comparison, the NPC figures represent conventional technology.

CHAPTER NINE

CONCLUSIONS

The results of this study consist of: (1) gas resource estimates for the Appalachian, Illinois, and Michigan basins presented in Chapter Two; (2) gas production estimates for the Appalachian basin based on traditional and conventional techniques presented in Chapter Five; and (3) gas production estimates for the Appalachian basin using advanced technologies in Chapter Six. These results are based on extrapolations of resource and production data from relatively small segments of the shale resource, notably the Big Sandy field of the Appalachian basin. Well-cost data are based on recent operating experience. Although resource and production estimates have been accomplished in a technically sound manner, the interrelated effects of market conditions, availability of natural gas supplies from other sources, and lead time required for developing advanced technologies could create a wide disparity in the projected production estimates. However, the following conclusions can be made:

- The natural gas resource base in Devonian Shale is prodigious. In the Appalachian basin alone, the gas in place is estimated to be between 225 TCF from black shale as determined by logs, to 1,861 TCF from both black and gray shales as determined by sample thickness.

  Average well production data from Devonian Shale within the Appalachian basin can be reasonably modeled by a hyperbolic decline of the form:

$$\text{Production Rate (MCF/D)} = C_1 \left[1 + \frac{5}{6} t \right]^{-\frac{2}{5}}$$

  The parameter C_1 serves as an index to characterize the average production decline.

- A significant correlation exists between the C_1 value and the black shale thickness determined from gamma-ray logs. The linear relationship between the C_1 constant and the gamma-ray log black shale thickness was determined to be 0.213. This relationship was used in the study to predict gas recovery from Devonian Shale in the Appalachian basin.

- Conventional hydraulic fracturing results in increased C_1 values over historical stimulation (shooting), the degree of improvement being dependent upon the C_1 values. Poorer wells appear to exhibit greater improvement due to fracturing than do the better wells. Questions remain on the extent of improvement obtainable with fracturing over shooting.

- The area available for drilling in the Appalachian basin is estimated to be 62,000 square miles, or about 56 percent of the total area. Practical considerations such as nondrillable urban areas and problems with lease restrictions exclude the remaining resource area. This reduces the drillable gas resource base in the black shales as determined by the log data from 225 TCF to 125 TCF. It likewise reduces the estimate based on both black and gray shale as determined by sample thickness from 1,861 TCF to 1,040 TCF.

- Significant levels of gas production from Devonian Shale in the Appalachian basin are possible in the next 20 years. The total producible gas in the Appalachian basin from Devonian Shale using conventional fracturing technology is estimated to be 37.4 TCF. When compared to the drillable gas resource base in the black shales of 125 TCF, an average recovery of 30 percent is indicated. However, Devonian Shale gas production in the coming years is likely to be controlled primarily by gas price and the level of technology development as compared to that of other resources (including conventional gas sources).

  The estimates of producible gas presented herein are based on a 30-year well lifetime. However, the production decline characteristics of Devonian Shale wells typically warrant a longer producing life, which results in greater reserve contributions. For this study, inclusion of additional production would have little economic impact on initial drilling decisions.

- Less than half (about 15 TCF) of the estimated 37.4 TCF of producible gas from Devonian Shale in the Appalachian basin using conventional fracturing technology can be produced at prices up to $3.50 per MMBtu at 10 percent ROR. The average price requirement (10 percent ROR for the entire 37.4 TCF) is $6.75 per MMBtu.

- The sparse production data for the Illinois and Michigan basins are insufficient to estimate production levels within those areas. However, the available shale mapping data compared with similar data for the Appalachian basin appear to offer production prospects at prices somewhat higher than for the Appalachian basin.

- Although efforts by government and industry are being directed toward the development of advanced technology, it is recognized that further work is required to develop optimized and sophisticated stimulation methods as well as more reliable exploration techniques. A limited amount of test data on the benefits of advanced technology exists today, which indicates that present day state-of-the-art technology can be improved. The projected estimates of producible gas through advanced technologies will be dependent upon the successful and continued research efforts in the area of extraction technologies.

- The limited demonstrated success of production technology for Devonian Shale represents a serious barrier to early exploitation of the resource by industry. Therefore, the key to accelerated development of the Devonian Shale resource is the demonstrated effectiveness of economically viable technology applications. The relatively limited well production data available for this and other similar studies discussed in Chapter Eight indicate that good prospects exist for Devonian Shale development by industry. To better understand the true potential and attendant risks, research efforts must be accompanied by dedicated well test programs designed to demonstrate the advantages of particular extraction techniques within specific formations of application. Such test programs are inherently expensive and should be planned to obtain essential data with as few test wells as practicable. However, shortcuts on either the number of wells or the specific tests to be performed, which provide insufficient data for adequate evaluation, only tend to delay the necessary demonstration of feasible extraction technology applications and their early acceptance by industry.

APPENDICES

APPENDIX A

Request Letter and Description of the National Petroleum Council

Department of Energy
Washington, D.C. 20585

June 20, 1978

Dear Mr. Chandler:

An objective of the energy supply initiatives of the President's energy policy is to promote domestic energy production from unconventional sources as well as from conventional sources. One of the areas to be encouraged is the recovery of natural gas from unconventional sources.

In the past, the National Petroleum Council has provided the Department of the Interior with appraisals on the extent and recovery of the Nation's oil and gas resources through such studies as Future Petroleum Provinces, U. S. Energy Outlook, Ocean Petroleum Resources, and Enhanced Oil Recovery.

Therefore, the National Petroleum Council is requested to prepare, as an early and important part of its new relationship with the Department of Energy, a study on unconventional sources of natural gas to include deep geopressured zones, Devonian shale, tight gas sands, and coal seams. Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for costs and recovery of unconventional gas and should consider how Government policy can improve the outlook.

For the purpose of this study, I will designate the Deputy Assistant Secretary for Policy and Evaluation to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

James R. Schlesinger
James R. Schlesinger
Secretary

Mr. Collis P. Chandler, Jr.
Chairman, National Petroleum
Council
1625 K Street, N. W.
Washington, D.C. 20006

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- Petroleum Resources Under the Ocean Floor (1969, 1971)
  Law of the Sea (1973)
  Ocean Petroleum Resources (1974, 1975)
- Environmental Conservation -- The Oil and Gas Industries (1971, 1972)
- U.S. Energy Outlook (1971, 1972)
- Emergency Preparedness for Interruption of Petroleum Imports into the United States (1973, 1974)
- Petroleum Storage for National Security (1975)
- Potential for Energy Conservation in the United States: 1974-1978 (1974)
  Potential for Energy Conservation in the United States: 1979-1985 (1975)
- Enhanced Oil Recovery (1976)

* Materials and Manpower Requirements (1979)

* Petroleum Storage & Transportation Capacities (1979).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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APPENDIX B
Study Group Rosters

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APPENDIX C
Geological Contour Maps

GEOLOGICAL CONTOUR MAPS

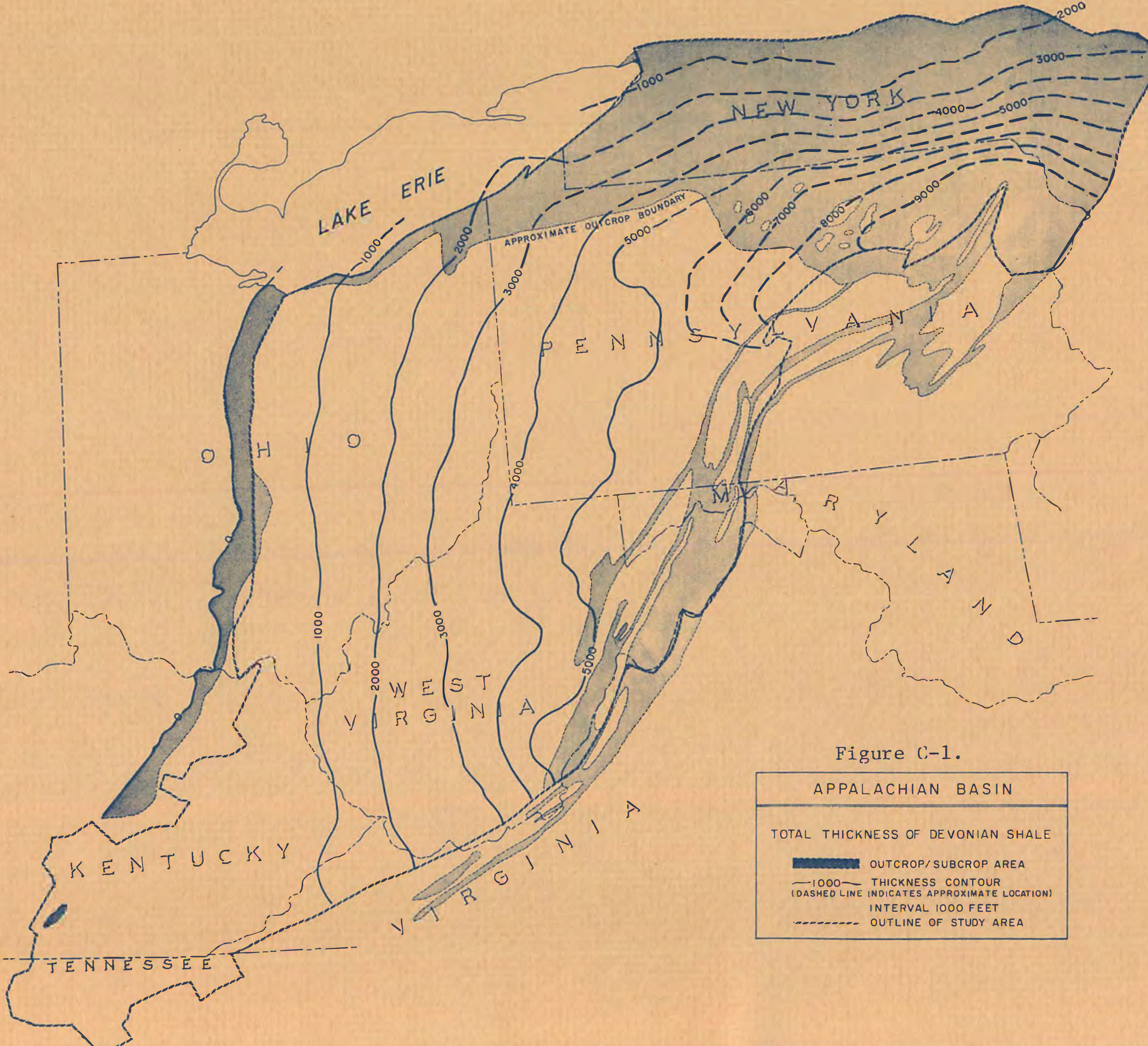

LAKE ERIE
NEW YORK
OHIO
PENNSYLVANIA
WEST VIRGINIA
MARYLAND
VIRGINIA
KENTUCKY
TENNESSEE
APPROXIMATE OUTCROP BOUNDARY
1000
2000
3000
4000
5000
6000
7000
8000
9000
APPALACHIAN BASIN
TOTAL THICKNESS OF DEVONIAN SHALE
OUTCROP/SUBCROP AREA
1000 THICKNESS CONTOUR
(DASHED LINE INDICATES APPROXIMATE LOCATION)
INTERVAL 1000 FEET
OUTLINE OF STUDY AREA

Figure C-1.

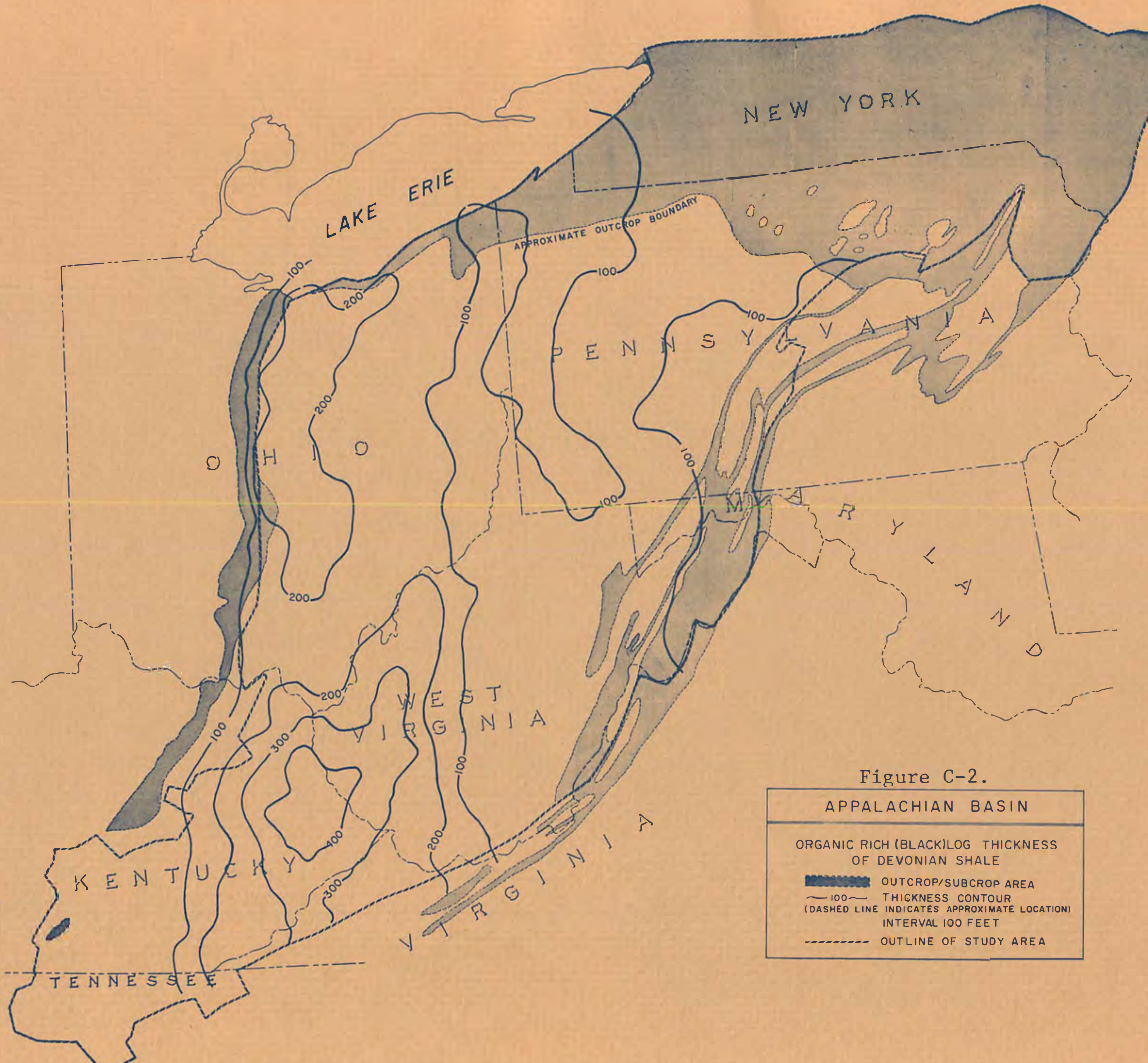
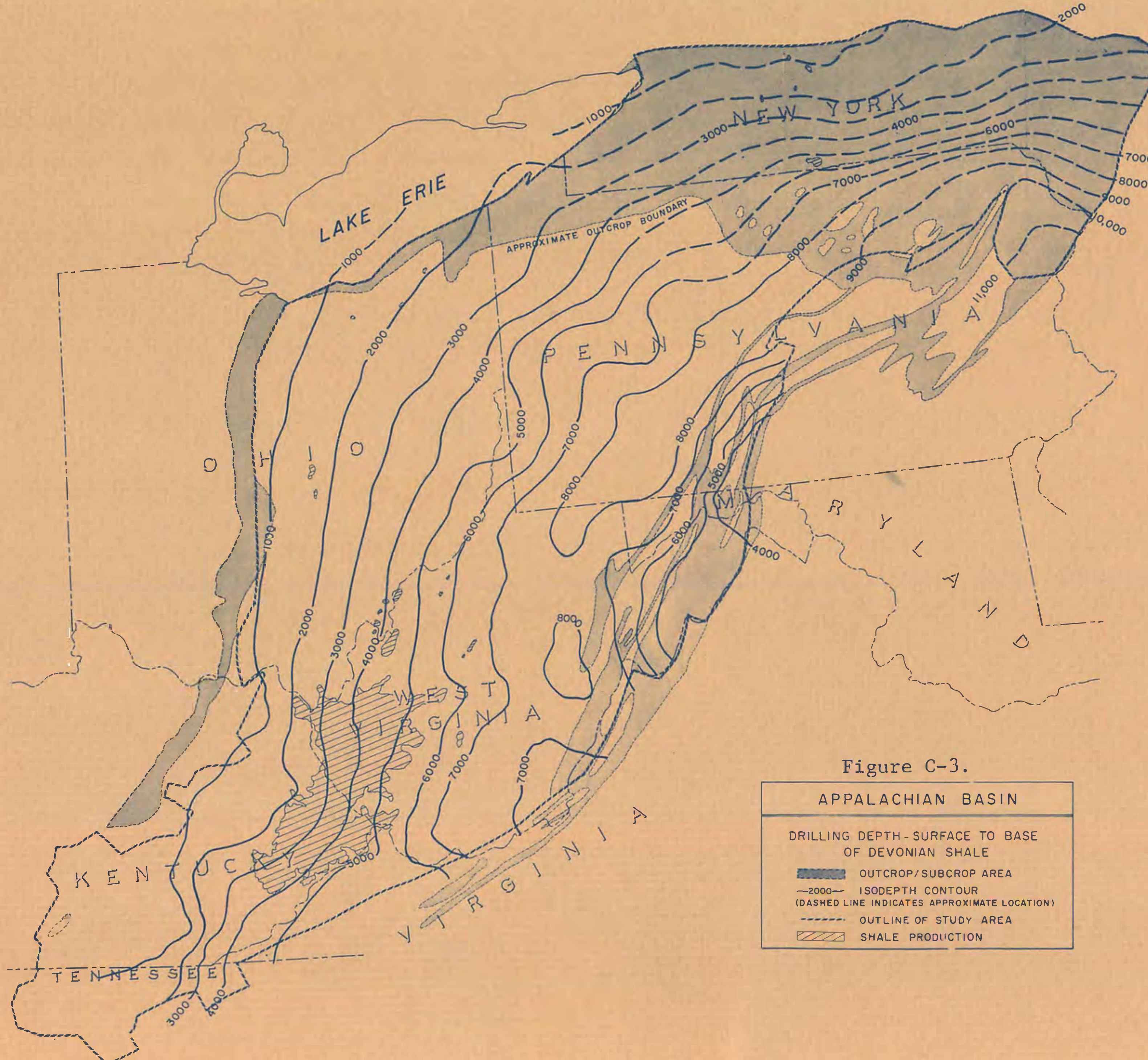

NEW YORK
LAKE ERIE
APPROXIMATE OUTCROP BOUNDARY
PENNSYLVANIA
OHIO
MARYLAND
WEST VIRGINIA
VIRGINIA
KENTUCKY
TENNESSEE
100
200
300
400
APPALACHIAN BASIN
ORGANIC RICH (BLACK) LOG THICKNESS OF DEVONIAN SHALE
OUTCROP/SUBCROP AREA
100 THICKNESS CONTOUR
(DASHED LINE INDICATES APPROXIMATE LOCATION)
INTERVAL 100 FEET
OUTLINE OF STUDY AREA

Figure C-2.



APPALACHIAN BASIN
DRILLING DEPTH - SURFACE TO BASE OF DEVONIAN SHALE
OUTCROP/SUBCROP AREA
—2000— ISODEPTH CONTOUR
(DASHED LINE INDICATES APPROXIMATE LOCATION)
OUTLINE OF STUDY AREA
SHALE PRODUCTION
LAKE ERIE
NEW YORK
PENNSYLVANIA
OHIO
WEST VIRGINIA
MARYLAND
VIRGINIA
KENTUCKY
TENNESSEE
APPROXIMATE OUTCROP BOUNDARY
1000
2000
3000
4000
5000
6000
7000
8000
9000
10,000
11,000

Figure C-3.

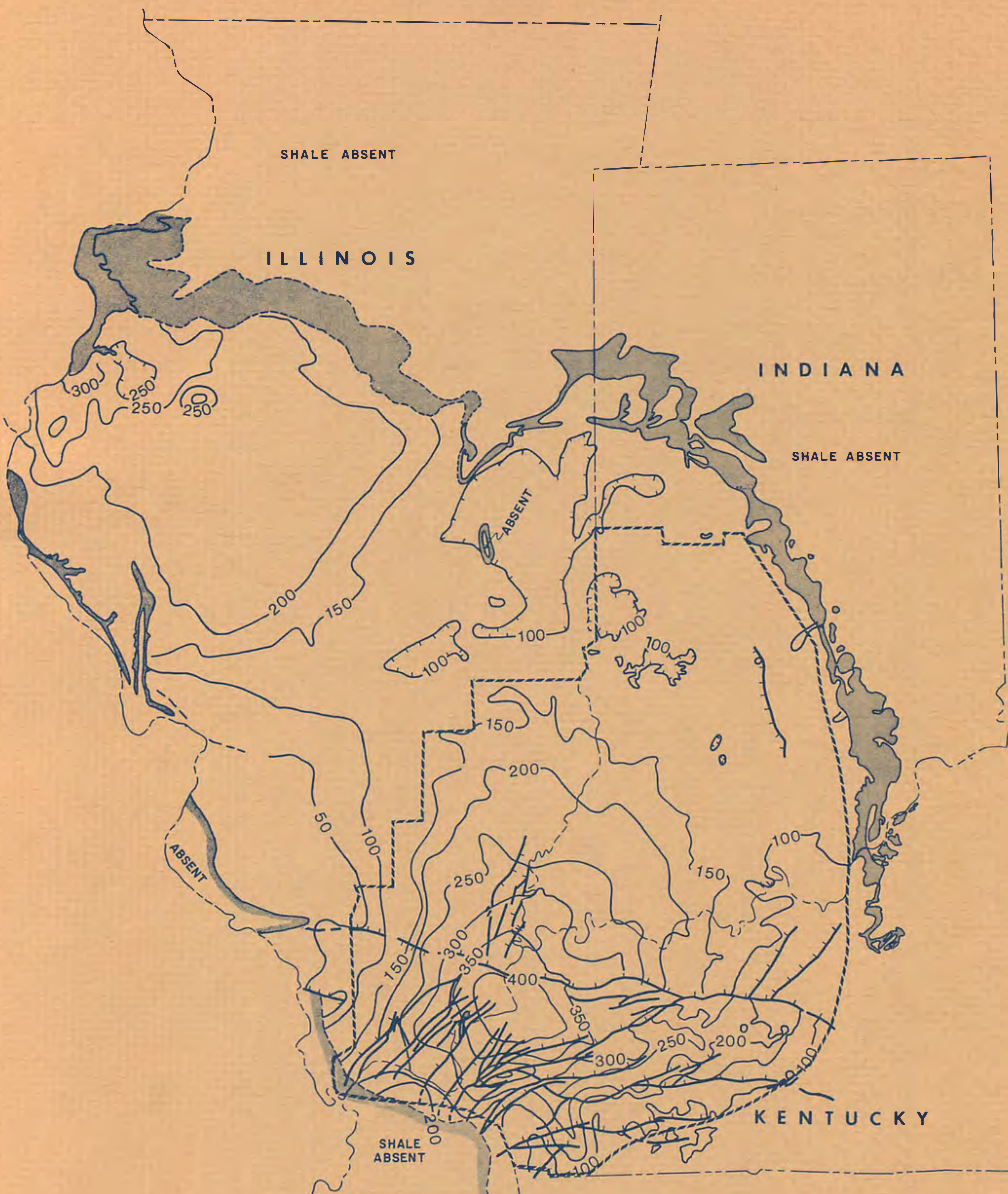


Figure C-4.

ILLINOIS BASIN

TOTAL THICKNESS OF DEVONIAN SHALE (NEW ALBANY)

OUTCROP/SUBCROP AREA

~250~ THICKNESS CONTOUR INTERVAL 50 FEET

OUTLINE OF STUDY AREA

FAULT (DOWN THROWN SIDE INDICATED)

Figure C-5.

ILLINOIS BASIN

DRILLING DEPTH - SURFACE TO BASE OF DEVONIAN (NEW ALBANY) SHALE

- OUTCROP/SUBCROP AREA
- 2000 ISODEPTH CONTOUR INTERVAL 500 FEET
- OUTLINE OF STUDY AREA
- SHALE PRODUCTION
- FAULT (DOWN THROWN SIDE INDICATED)

Figure C-6.

MICHIGAN BASIN

TOTAL THICKNESS OF ANTRIM SHALE
(EXCLUDES ELLSWORTH SHALE)

OUTCROP/SUBCROP AREA
—200— THICKNESS CONTOUR
(DASHED LINE INDICATES APPROXIMATE LOCATION)
INTERVAL 100 FEET
OUTLINE OF STUDY AREA

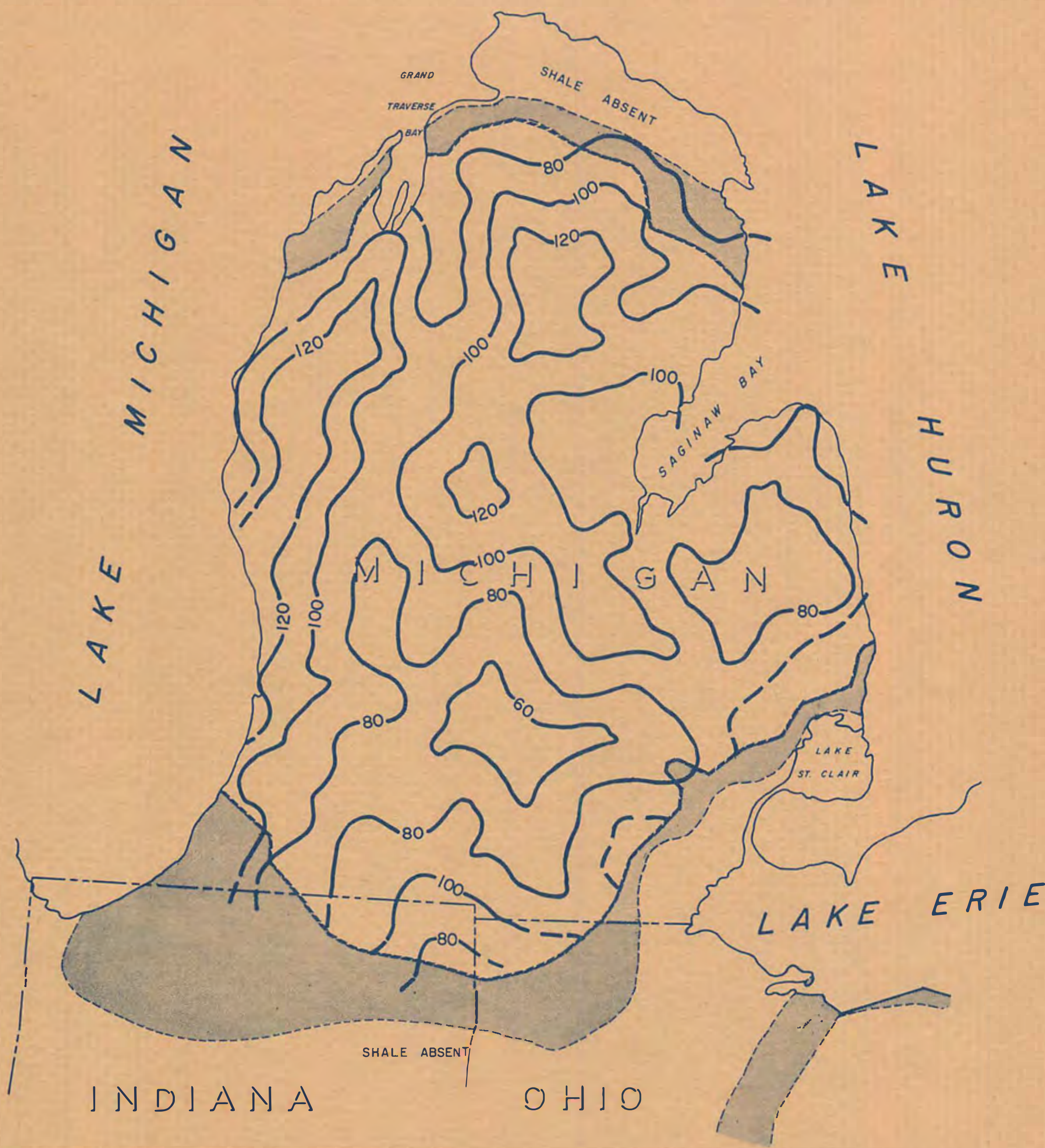


Figure C-7.

MICHIGAN BASIN

ORGANIC RICH (BLACK) LOG THICKNESS OF ANTRIM SHALE (UNITS IA, IC & 2)

OUTCROP/SUBCROP AREA

—100— THICKNESS CONTOUR (DASHED LINE INDICATES APPROXIMATE LOCATION)

INTERVAL 20 FEET

OUTLINE OF STUDY AREA

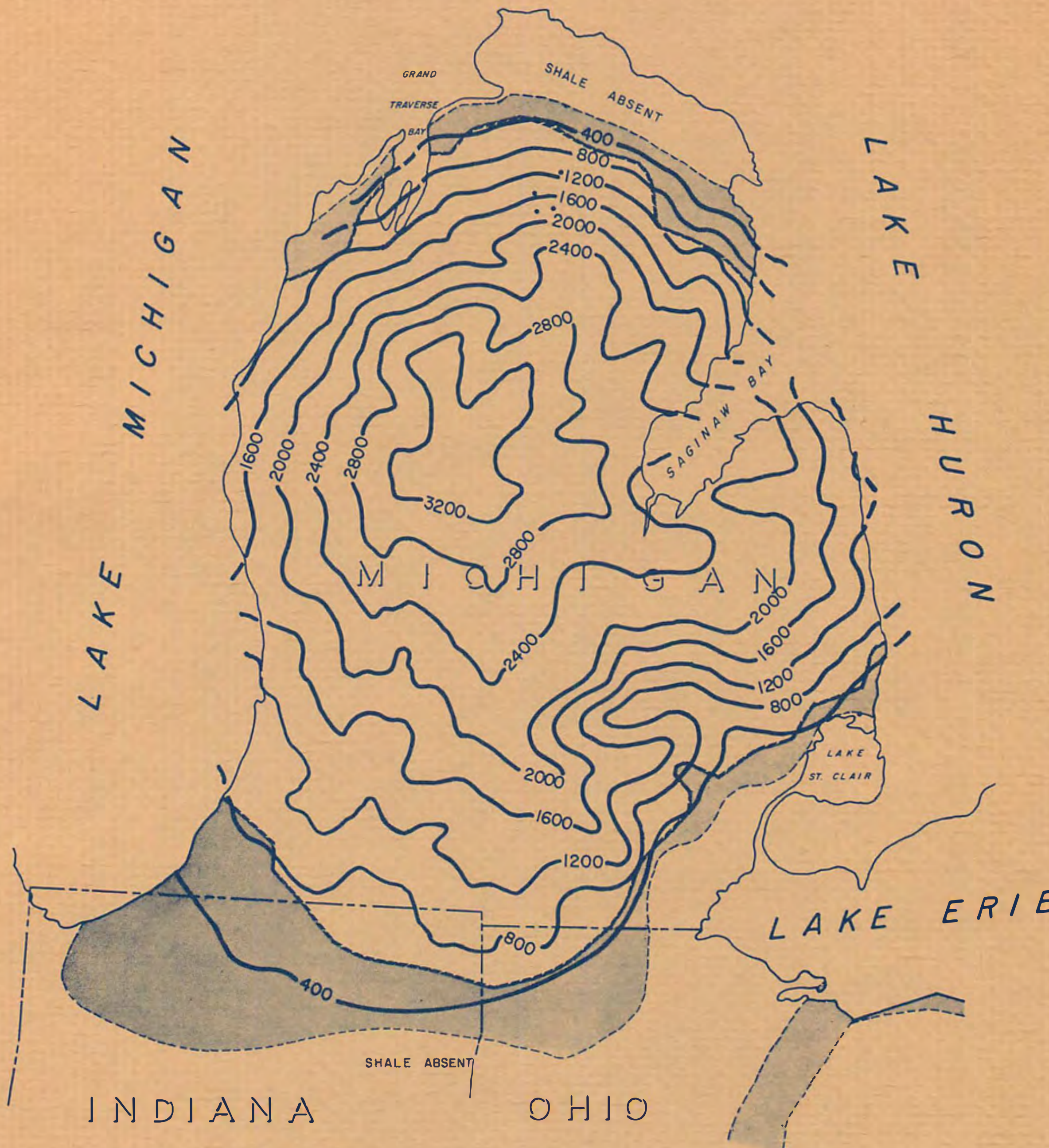


Figure C-8.

MICHIGAN BASIN

DRILLING DEPTH - SURFACE TO BASE OF ANTRIM SHALE

OUTCROP/SUBCROP AREA
~2000~ ISODEPTH CONTOUR
(DASHED LINE INDICATES APPROXIMATE LOCATION)
INTERVAL 400 FEET
OUTLINE OF STUDY AREA
SHALE PRODUCTION

APPENDIX D

Gas Resource Basin Data by State

GAS RESOURCE BASIN DATA BY STATE

TABLE D-1

Appalachian Basin
Devonian Shale Resource Assessment Summarized by State
(Log Data)

	Black Shale			Gray Shale			Total Shale Resource		
	Average Thickness (Feet)	Land Area* (Sq Mi)	Total (TCF)	Average Thickness (Feet)	Land Area* (Sq Mi)	Total (TCF)	Average Depth (Feet)	Total (TCF)	Average (BCF/Sq Mi)
Kentucky	200	12,829	43	134	12,829	5	1,885	48	4
Maryland	83	1,087	1	3,661	1,087	11	6,120	12	12
New York	59	19,069	19	2,731	19,069	145	3,045	164	9
Ohio	157	21,892	58	1,442	21,892	88	2,500	146	7
Pennsylvania	92	29,017	45	5,407	29,017	437	6,790	482	17
Tennessee	48	2,338	2	30	2,338	0.2	1,395	2	1
Virginia	238	1,915	8	1,867	1,915	10	5,535	18	9
West Virginia	128	22,984	49	3,252	22,984	209	6,275	258	11
Grand Total	120	111,131	225	2,921	111,131	905	4,485	1,130	10

*Land area encompasses that portion considered as having Devonian Shale potential, and does not necessarily represent the total area of the state.

TABLE D-2

Appalachian Basin
Devonian Shale Resource Assessment Summarized by State
(Sample Data)

	Black Shale			Gray Shale			Total Shale Resource		
	Average Thickness (Feet)	Land Area* (Sq Mi)	Total (TCF)	Average Thickness (Feet)	Land Area* (Sq Mi)	Total (TCF)	Average Depth (Feet)	Total (TCF)	Average (BCF/Sq Mi)
Kentucky	249	12,829	53	92	12,829	3	1,885	56	4
Maryland	919	1,087	17	2,825	1,087	8	6,120	25	23
New York	619	19,069	198	2,171	19,069	115	3,045	313	16
Ohio	426	21,892	156	1,173	21,892	72	2,500	228	10
Pennsylvania	853	29,017	414	4,646	29,017	376	6,790	790	27
Tennessee	78	2,338	3	0	2,338	0	1,395	3	12
Virginia	465	1,915	15	1,640	1,915	9	5,535	24	12
West Virginia	640	22,984	246	2,741	22,984	176	6,275	422	18
Grand Total	592	111,131	1,102	2,450	111,131	759	4,485	1,861	17

*Land area encompasses that portion considered as having Devonian Shale potential, and does not necessarily represent the total area of the state.

TABLE D-3

Illinois Basin
Devonian Shale Resource Assessment Summarized by State

	Total Shale		Total Shale Resource	
	Average Thickness (Feet)	Land Area* (Sq Mi)	Total (TCF)	Average (BCF/Sq Mi)
Illinois	213	7,484	28	4
Indiana	141	11,597	28	2
Kentucky	194	9,069	30	3
Grand Total	177	28,150	86	3

*Land area encompasses that portion considered as having Devonian Shale potential, and does not necessarily represent the total area of the state.

TABLE D-4

Michigan Basin
Devonian Shale Resource Assessment Summarized by State
(Log Data)

	Black Shale			Gray Shale			Total Shale Resource		
	Average Thickness (Feet)	Land Area* (Sq Mi)	Total (TCF)	Average Thickness (Feet)	Land Area* (Sq Mi)	Total (TCF)	Average Depth (Feet)	Total (TCF)	Average (BCF/Sq Mi)
Indiana	92	819	1	101	819	0.2	675	1	2
Michigan	93	34,081	53	218	34,081	21	1,890	74	2
Ohio	107	500	1	67	500	0.1	600	1	2
Grand Total	93	35,400	55	214	35,400	21	1,850	76	2

*Land area encompasses that portion considered as having Devonian Shale potential, and does not necessarily represent the total area of the state.

APPENDIX E

Field Gas Compression and Suction Trunkline Facility Costs

FIELD GAS COMPRESSION AND SUCTION TRUNKLINE FACILITY COSTS

It is generally the responsibility of the producer operating in the Appalachian area to install the production line from the well to the nearest point on the buyer's pipeline. The buyer is usually the gas utility which owns the gathering trunklines in the immediate vicinity. The utility's trunkline will be a relatively low-pressure line or suction line connected to a central compressor facility where the low-pressure field gas is upgraded for delivery into the high-pressure transmission system.

The economic analysis presented in Chapters Five and Six of the text is based on burdening the producer with the well and field line costs to the point of sale at the buyer's line. Since the utility owns and operates the facilities downstream from the sales point, including the suction trunklines and compressor plant, these costs were not included. However, it is recognized that suction lines and compression are an incremental cost of production, regardless of the ownership, and this cost must be eventually borne by the consumer. For this reason these estimated costs are considered in the following separate analysis. Since Devonian Shale is considered an underpressured reservoir, the wells are characteristically produced into a low-pressure gathering line system and would require compression throughout their productive life.

A simple compression and suction line system configuration is adequate for the purpose of determining the unit cost on an after-tax basis. The generalized case assumes a 1,000 MCF/D rate from 50 wells drilled in a 16-square mile area, feeding into two 4-mile segments of 10-inch compressor suction lines. The field pressure would be 25 pounds per square inch gauge (psig) and the gas would be compressed to transmission pressure of 500 psig. The investment and operating costs are given below. The cost for measurement of field purchases and maintenance is not of significant magnitude and can be ignored. The cost of fuel consumption to operate the facilities was based on the low and high range of field prices ($2.50 and $9.00 per MMBtu). The economic parameters based on an effective federal and state income tax rate of 48 percent, 10 percent investment tax credit, and 30-year depreciable investment, were used to compute the unit cost at ROR's of 10, 15, and 20 percent.

Assumptions:

- Average well flow of 20 MCF/D per well
- Requirements for 1 MMCF/D delivery = 50 wells
- Producing area based on 160-acre spacing for 50 wells + proportional nondrillable area = 16 square miles
- Suction line investment for two 4-mile segments of 10-inch lines at $20 per foot installed = $845,000

- Compression horsepower (hp) (25 psig suction and 500 psi discharge) = 160 hp per MMCF/D

- Compression investment (160 hp) at $1,000 per installed hp = $160,000

- Compression O&M annual expense[1] at $65 per hp-year = $10,400 per year

- Compression annual fuel cost at 8,500 Btu per hp-hr and
  (1) fuel cost of $2.50 per MMBtu = $29,800 per year
  (2) fuel cost of $9.00 per MMBtu = $107,200 per year

- Heating value of gas based on 1,100 Btu = 1 cubic foot

Table E-1 gives the estimated unit cost for field compression and related trunkline suction facilities computed at the respective ROR's.

At the ROR of 10 percent, the $0.49 compression cost increases the $2.50 price to $2.99 by a factor of 1.2. This is not out of line with current practices in the industrial drilling programs called "self-help gas" in the Appalachian area. The industrial concern is assessed a handling charge per MCF by the utility, which is equivalent to about 20 percent of the field price, to transport the gas from the point where it enters the utility's field line.

TABLE E-1

(Constant 1979 Dollars)

Rate of Return	Compression ($ per MMBtu) *	Compression ($ per MMBtu) †	Trunkline (Suction) ($ per MMBtu)	Total ($ per MMBtu) *	Total ($ per MMBtu) †
10%	0.16 to	0.35	0.33	0.49 to	0.68
15%	0.19 to	0.39	0.50	0.69 to	0.89
20%	0.23 to	0.42	0.68	0.91 to	1.10

*Based on $2.50 per MMBtu fuel cost for compression.
†Based on $9.00 per MMBtu fuel cost for compression.

[1]Compression O&M expense based on 32 field compression stations' actual costs in 1979 dollars.

APPENDIX F

Drillable Area Data by County for the Appalachian Basin

DRILLABLE AREA DATA BY COUNTY
FOR THE APPALACHIAN BASIN

TABLE F-1

Ohio
Estimate of Drillable Areas by County
(Area in Square Miles)

County Name	Shale Area	Crop Lands	Pasture	Forest	Natural Barriers 1/	Total Rural Area	Less Storage Fields	Less State Parks	Less Rural Highways (incl. w/other)	Shale Producing Areas	Less Others 4% 2/	Potential Lease Lands	Leaseable Properties (85%xPotential) 3/	Drillable Areas (75%xLeaseable) 4/	
Ashland	418	N/A	N/A	N/A	63	355	-25	0		0	-14	316	269	201	48%
Ashtabula	706	N/A	N/A	N/A	106	600	0	-8		-71	-24	497	422	317	45%
Athens	504	N/A	N/A	N/A	76	428	0	0		0	-17	411	349	262	52%
Belmont	535	N/A	N/A	N/A	107	428	0	-2		0	-17	409	348	261	49%
Carroll	388	N/A	N/A	N/A	58	330	0	0		0	-13	317	269	202	52%
Columbiana	535	N/A	N/A	N/A	80	455	-7	-4		0	-18	426	362	272	51%
Coshocton	545	N/A	N/A	N/A	82	463	0	0		0	-19	444	377	283	52%
Crawford	270	N/A	N/A	N/A	27	243	0	0		0	-10	233	198	149	55%
Cuyahoga	456	N/A	N/A	N/A	410	46	0	0		0	-2	44	37	28	6%
Delaware	220	N/A	N/A	N/A	33	187	0	0		0	-7	180	153	115	52%
Erie	87	N/A	N/A	N/A	9	78	0	0		0	-3	75	64	48	55%
Fairfield	505	N/A	N/A	N/A	76	429	0	-5		0	-17	407	346	259	51%
Franklin	268	N/A	N/A	N/A	134	134	0	0		0	-5	129	110	82	31%
Gallia	471	N/A	N/A	N/A	71	400	0	0		0	-16	384	326	245	52%
Geauga	407	N/A	N/A	N/A	102	305	0	0		0	-12	293	249	187	46%
Guernsey	519	N/A	N/A	N/A	78	441	0	-32		0	-18	391	332	249	48%
Harrison	403	N/A	N/A	N/A	81	322	0	0		0	-13	309	263	197	49%
Hocking	420	N/A	N/A	N/A	63	357	-10	-5		0	-14	328	279	209	50%
Holmes	423	N/A	N/A	N/A	63	360	-10	-2		0	-14	334	284	213	50%
Huron	397	N/A	N/A	N/A	40	357	0	0		0	-14	343	292	219	55%
Jackson	420	N/A	N/A	N/A	63	357	0	0		0	-14	343	292	219	52%
Jefferson	411	N/A	N/A	N/A	62	349	0	-2		0	-14	333	283	212	52%
Knox	523	N/A	N/A	N/A	78	445	-5	0		0	-18	422	359	269	51%
Lake	232	N/A	N/A	N/A	46	186	0	0		-16	-7	163	139	104	45%
Lawrence	456	N/A	N/A	N/A	68	388	0	0		-32	-16	340	289	217	48%
Licking	686	N/A	N/A	N/A	103	583	0	0		-7	-23	553	470	353	51%
Lorain	495	N/A	N/A	N/A	124	371	-10	0		0	-15	346	294	221	45%
Mahoning	419	N/A	N/A	N/A	84	335	0	0		0	-13	322	274	205	49%
Medina	424	N/A	N/A	N/A	64	360	-10	-2		0	-14	334	284	213	50%
Meigs	434	N/A	N/A	N/A	65	369	0	-2		-13	-15	339	288	216	50%
Monroe	455	N/A	N/A	N/A	91	364	0	0		0	-15	349	297	222	49%
Morgan	417	N/A	N/A	N/A	63	354	0	-5		0	-14	335	285	214	51%
Morrow	390	N/A	N/A	N/A	58	332	0	0		0	-13	319	271	203	52%
Muskingum	663	N/A	N/A	N/A	99	564	-6	-11		0	-23	524	445	334	50%
Noble	399	N/A	N/A	N/A	60	339	0	-2		0	-14	323	275	206	52%
Perry	409	N/A	N/A	N/A	61	348	0	0		0	-14	334	284	213	52%
Pickaway	183	N/A	N/A	N/A	27	156	0	0		0	-6	150	128	96	52%
Pike	280	N/A	N/A	N/A	42	238	-5	-2		0	-10	221	188	141	50%
Portage	504	N/A	N/A	N/A	101	403	0	-2		0	-16	385	327	245	49%
Richland	497	N/A	N/A	N/A	75	422	0	0		0	-17	405	344	258	52%
Ross	353	N/A	N/A	N/A	53	300	0	-1		0	-12	287	244	183	52%
Scioto	609	N/A	N/A	N/A	91	518	0	-2		0	-21	495	421	316	52%
Stark	573	N/A	N/A	N/A	115	458	-30	-4		0	-18	406	345	259	45%
Summit	413	N/A	N/A	N/A	165	248	-25	-13		0	-10	200	170	128	31%
Trumbull	620	N/A	N/A	N/A	155	465	0	-19		0	-19	427	363	272	44%
Tuscarawas	551	N/A	N/A	N/A	83	468	0	0		0	-19	449	382	286	52%
Vinton	411	N/A	N/A	N/A	62	349	-4	-2		0	-14	329	280	210	51%
Washington	637	N/A	N/A	N/A	96	541	0	0		0	-22	519	441	331	52%
Wayne	551	N/A	N/A	N/A	83	468	-23	0		0	-19	426	362	272	49%
Total	21,892					17,796(81%)						16,648 76%		10,616	48%

1/ Natural barriers consist of urban areas, lakes, swamp areas, government non-leaseable lands.
2/ Other - R/W rural highways, railroads, waterways, airports, golf courses, etc. which assumes that 4% of total rural area is not potential leaseable lands.
3/ Leaseable properties assume that 15% of potential lease lands cannot be leased because of land-owner refusal, etc. (based on actual experience).
4/ Drillable areas assume that 25% of leaseable properties cannot be drilled due to bad titles, landowner problems, lack of right of way access, including 10% operated leaseholds committed by investors to other drilling programs.

TABLE F-2

Northern Pennsylvania
Estimate of Drillable Areas by County
(Area in Square Miles)

County Name	Shale Area	Crop Lands	Pasture	Forest	Urban	Total Rural Area 1/	Less Storage Fields	Less State Parks, Rural Highways 2/	Shale Producing Areas 3/	Less Other 3% 4/	Potential Lease Lands	Leaseable Properties (85%xPotential) 5/	Drillable Area (80%xLeaseable) 6/	
Bradford	1,148	347	135	537	129	1,019	0	-53	None	-31	935	795	636	55%
Cameron	401	2	1	388	10	391	-16	-44	None	-12	319	271	217	54%
Carbon	8	-	-	-	-	8	-	-	None	-	8	7	5	68%
Centre	558	82	12	414	50	508	0	-28	None	-15	465	395	316	57%
Clarion	597	98	23	423	53	544	-5	-34	None	-16	489	416	333	56%
Clearfield	1,139	67	17	950	105	1,034	-2	-35	None	-31	966	821	657	58%
Clinton	629	35	6	568	20	609	-69	-39	None	-18	483	411	328	52%
Columbia	97	33	3	49	12	85	0	-8	None	-3	74	63	50	52%
Crawford	1,012	343	93	466	110	902	0	-76	None	-27	799	679	543	54%
Elk	807	27	2	737	41	766	-50	-15	None	-23	678	576	461	57%
Erie	813	223	64	297	229	584	-3	-39	None	-18	524	445	356	44%
Forest	419	8	3	394	15	404	-3	-22	None	-12	367	312	250	60%
Jefferson	652	90	16	458	88	564	-6	-36	None	-17	505	429	343	53%
Lackawanna	295	33	10	177	75	220	0	-13	None	-7	200	170	136	46%
Luzerne	177	20	5	119	33	144	0	-11	None	-4	129	110	88	50%
Lycoming	730	86	13	561	70	660	0	-23	None	-20	617	524	420	57%
McKean	992	33	16	903	41	951	-8	-17	None	-29	897	762	610	61%
Mercer	670	200	60	212	197	473	-4	-25	None	-14	430	366	292	44%
Monroe	428	31	6	292	99	329	0	-24	None	-10	295	251	201	47%
Pike	542	9	3	476	53	489	0	-25	None	-15	449	382	305	56%
Potter	1,092	74	15	966	36	1,056	-104	-24	None	-32	896	762	609	56%
Sullivan	478	25	16	404	33	445	0	-32	None	-13	400	340	272	57%
Susquehanna	833	177	119	442	95	738	0	-29	None	-22	687	584	467	56%
Tioga	1,146	200	117	729	104	1,042	-52	-31	None	-31	928	789	631	55%
Venango	678	58	15	552	53	625	0	-24	None	-19	582	495	396	58%
Warren	905	54	46	753	52	853	-3	-24	None	-26	800	680	544	60%
Wayne	741	107	105	432	97	644	0	-27	None	-19	598	508	407	55%
Wyoming	398	83	38	231	46	352	0	-12	None	-11	329	280	224	56%
Total	18,385					16,439(89%)					14,849(81%)		10,097	55%

1/ Total rural area includes crop lands, pasture and forest, state game lands and state forest lands and national forest parks.
2/ State Park areas include native parks, historical properties, but are exclusive of state forest lands, state game lands and national forest parks.
3/ Producing shale areas which are not subject to in fill drilling.
4/ Other - R/W railroads, waterways, airports, golf courses, etc. which assumes that 3% of total rural area is not potential leaseable lands.
5/ Leaseable properties assume that 15% of potential lease lands cannot be leased because of land owner refusal, coal mining problems (based on actual experience).
6/ Drillable areas assume that 20% of leaseable properties cannot be drilled due to bad titles, land owner problems, lack of right of way access, including 5% operated leaseholds committed by investors to other drilling programs.

Data source: Pennsylvania Department of Commerce: County Industrial Report Series by Bureau of Statistics.

TABLE F-3

Southern Pennsylvania
Estimate of Drillable Areas by County
(Area in Square Miles)

County Name	Shale Area	Crop Lands	Pasture	Forest	Urban	Total 1/ Rural Areas	Less Storage Fields	Less State 2/ Parks, Rural Highways	Shale 3/ Producing Areas	Less 4/ Other 3%	Potential Lease Lands	Leaseable 5/ Properties (85%xPotential)	Drillable 6/ Areas (80%xLeaseable)	
Allegheny	728	42	20	135	540	188	-13	-30	0	-6	139	118	95	13%
Armstrong	658	143	40	343	125	533	-15	-32	0	-16	470	400	320	49%
Beaver	440	75	29	210	126	314	-5	-34	0	-9	266	226	181	41%
Butler	794	211	29	409	144	650	-1	-60	0	-20	569	484	387	49%
Cambria	695	120	12	445	118	577	-11	-36	0	-17	513	436	349	50%
Fayette	802	132	37	501	132	670	-0	-81	0	-20	569	484	387	48%
Greene	578	51	88	231	207	371	-29	-22	0	-11	309	263	210	36%
Indiana	825	206	42	447	130	695	-17	-40	0	-21	617	524	420	51%
Somerset	1,085	199	66	693	120	965	-0	-92	0	-29	844	717	574	53%
Washington	857	203	200	300	154	703	-7	-53	0	-21	622	529	423	49%
Westmoreland	1,024	178	58	488	300	724	-58	-66	0	-22	578	491	393	38%
Lawrence	367	107	37	145	78	289	-0	-22	0	-9	258	219	175	48%
Bedford	1,018	187	71	660	100	918	-0	-39	0	-28	851	723	579	57%
Blair	530	99	12	348	71	459	-0	-15	0	-14	430	366	292	55%
Huntingdon	231	34	8	172	17	214	-0	- 5	0	- 6	203	173	138	60%
Total	10,632					8,270 (78%)					7,238 (68%)		4,923	(46%)

1/ Total rural area includes crop lands, pasture and forest, state game lands and state forest lands and national forest parks.
2/ State Park areas include native parks, historical properties, but are exclusive of state forest lands, state game lands and national forest parks.
3/ Producing shale areas which are not subject to in fill drilling.
4/ Other - R/W railroads, waterways, airports, golf courses, etc. which assumes that 3% of total rural area is not potential leaseable lands.
5/ Leaseable properties assume that 15% of potential lease lands cannot be leased because of land owner refusal, coal mining problems (based on actual experience).
6/ Drillable areas assume that 20% of leaseable properties cannot be drilled due to bad titles, land owner problems, lack of right of way access, including 5% operated leaseholds committed by investors to other drilling programs.

Data Source: Pennsylvania Department of Commerce: County Industrial Report Series by Bureau of Statistics.

TABLE F-4

Maryland and Northern West Virginia
Estimate of Drillable Areas by County
(Area in Square Miles)

County Name	Shale Area	Crop Lands	Pasture	Forest	Urban 1/ (Estimated)	Total Rural Area	Less Storage Fields	Less 2/ State Parks Lakes State Forests	Less Rural Highways (incl. w/other)	Shale 3/ Producing Areas	Less 4/ Other 3%	Potential Lease Lands	Leaseable 5/ Properties (85%xPotential)	Drillable 6/ Areas (85%xLeaseable)	
Maryland:															
Garrett	659	N/A	N/A	N/A	37	622	-10	0		0	-19	593	504	428	65%
Allegany	428	N/A	N/A	N/A	24	404	0	0		0	-12	392	333	283	66%
Total	1,087					1,026						985		711	(65%)
Northern West Virginia:															
Braxton	517	N/A	N/A	N/A	22	495	0	-5		0	-15	475	404	343	66%
Brooke	88	N/A	N/A	N/A	18	70	0	0		0	-2	68	58	49	56%
Calhoun	281	N/A	N/A	N/A	12	269	0	0		0	-8	261	222	189	67%
Doddridge	319	N/A	N/A	N/A	10	309	0	0		0	-9	300	255	217	68%
Gilmer	339	N/A	N/A	N/A	18	321	-1	-5		0	-10	305	259	220	65%
Hancock	83	N/A	N/A	N/A	25	58	0	-2		0	-2	54	46	39	47%
Harrison	418	N/A	N/A	N/A	36	382	-73	-1		0	-11	297	252	215	51%
Jackson	461	N/A	N/A	N/A	19	442	-2	0		0	-13	427	363	309	67%
Lewis	392	N/A	N/A	N/A	26	366	-19	-4		0	-11	332	282	240	61%
Marion	311	N/A	N/A	N/A	27	284	-5	-2		0	-9	268	228	194	62%
Munhall	304	N/A	N/A	N/A	20	284	-2	0		0	-9	273	232	197	65%
Mason	433	N/A	N/A	N/A	18	415	0	0		0	-12	403	343	291	67%
Monongalia	365	N/A	N/A	N/A	32	333	0	-3		0	-10	320	272	231	63%
Ohio	106	N/A	N/A	N/A	30	76	0	0		0	-2	74	63	54	50%
Pleasants	129	N/A	N/A	N/A	7	122	0	0		0	-4	118	100	85	66%
Pocohantas	849	N/A	N/A	N/A	24	825	0	-2		0	-25	798	678	577	68%
Preston	645	N/A	N/A	N/A	26	619	0	-20		0	-19	580	493	419	65%
Randolph	1,036	N/A	N/A	N/A	24	1,012	0	-15		0	-30	967	822	699	67%
Ritchie	452	N/A	N/A	N/A	20	432	-13	-2		0	-13	404	343	292	65%
Roane	486	N/A	N/A	N/A	19	467	-5	0		0	-14	448	381	324	67%
Taylor	174	N/A	N/A	N/A	8	166	0	-5		0	-5	156	133	113	65%
Tucker	421	N/A	N/A	N/A	9	412	0	-14		0	-12	386	328	279	66%
Tyler	256	N/A	N/A	N/A	11	245	0	0		0	-7	238	202	172	67%
Upshur	352	N/A	N/A	N/A	15	337	0	-1		0	-10	326	277	236	67%
Webster	551	N/A	N/A	N/A	10	541	0	-13		0	-16	512	435	370	67%
Wetzel	363	N/A	N/A	N/A	18	345	-6	0		0	-10	329	280	238	65%
Wirt	235	N/A	N/A	N/A	8	227	0	0		0	-7	220	187	159	68%
Wood	368	N/A	N/A	N/A	39	329	0	0		0	-10	319	271	230	63%
Barbour	341	N/A	N/A	N/A	17	324	0	-1		0	-10	313	266	226	66%
Grant	478	N/A	N/A	N/A	60	418	0	-2		0	-13	403	343	291	61%
Hardy	585	N/A	N/A	N/A	95	490	0	-1		0	-15	474	403	342	59%
Hampshire	639	N/A	N/A	N/A	109	530	0	0		0	-16	514	437	371	58%
Mineral	330	N/A	N/A	N/A	47	283	0	0		0	- 8	275	234	199	60%
Morgan	80	N/A	N/A	N/A	8	72	0	-5		0	- 2	65	55	47	59%
Pendleton	695	N/A	N/A	N/A	99	596	0	-2		0	-18	576	490	416	60%
W.V. Total	13,882					12,842(93%)						12,278(88%)		8,873	(64%)

1/ Urban areas consist of metro areas and rural towns.
2/ Assumes drilling in national forest areas.
3/ Current shale producing areas not excluded because of possible drilling in lower interval.
4/ Other - R/W rural highways, railroads, waterways, airports, golf courses, etc. which assumes that 3% of total rural area is not potential leaseable lands
5/ Leaseable properties assume that 15% of potential lease lands cannot be leased.
6/ Drillable areas assume that 15% of leaseable properties cannot be drilled (col. 5 & 6 based on actual experience).

TABLE F-5

Southern West Virginia
Estimate of Drillable Areas by County
(Area in Square Miles)

County Name	Shale Area	Urban[1/] (Estimated)	Total Rural Area	Less Storage Fields	Less[2/] State Parks & State Forests	Shale[3/] Producing Area	Less[4/] Other (3%)	Potential Lease Lands	Leaseable[5/] Properties (85% X Pot.)	Drillable[6/] Areas (85% X Leaseable)	
Boone	501	28	473	0	- 2	- 74	-14	383	326	277	55%
Cabell	279	35	244	0	-20	-174	- 7	43	37	31	11%
Clay	343	19	324	0	- 2	0	-10	312	265	225	66%
Fayette	663	52	611	0	-26	- 2	-18	565	480	408	62%
Greenbrier	1,026	20	1,006	0	-25	0	-30	951	808	687	67%
Kanawha	907	60	847	-71	-39	0	-25	712	605	514	57%
Lincoln	438	22	416	0	- 2	-333	-12	69	59	50	11%
Logan	456	42	414	0	- 7	- 79	-12	316	269	228	50%
McDowell	533	46	487	0	-14	0	-15	458	389	331	62%
Mercer	334	28	306	0	-14	0	- 9	283	241	204	61%
Mingo	423	21	402	0	- 2	-170	-12	218	185	158	37%
Monroe	237	21	216	0	- 1	0	- 6	209	178	151	64%
Nicholas	642	27	615	0	-15	0	-18	582	495	421	66%
Putnam	348	18	330	-20	-15	- 87	-10	198	168	143	41%
Raleigh	605	53	552	0	- 4	0	-17	531	451	384	63%
Summers	350	14	336	0	-32	0	-10	294	250	212	61%
Wayne	513	23	490	0	-18	-317	-15	140	119	101	20%
Wyoming	504	29	475	0	-42	0	-14	419	356	303	60%
Total	9,102		8,544 (94%)					6,683 (74%)		4,828	(53%)

1/ Urban areas consist of metro areas and rural towns.
2/ Assumes drilling in national forest areas.
3/ Shale producing area includes protective acreage.
4/ Other - R/W railroads, waterways, airports, golf courses, etc., which would not be considered potential leaseable lands.
5/ Leaseable properties assume that 15% of potential lease lands cannot be leased because of landowner refusal, coal mining problems (based on actual experience).
6/ Drillable areas assume that 15% of leaseable properties cannot be drilled due to bad title, landowner problems, lack of right of way access.

TABLE F-6

Tennessee and Virginia
Estimate of Drillable Areas by County
(Area in Square Miles)

County Name	Shale Area	Urban 1/ (Estimated)	Total Rural Area	Less 2/ State Parks & State Forests	Shale Producing Area	Less 3/ Other (3%)	Potential Lease Lands	Leaseable 4/ Properties (85% X Pot.)	Drillable 5/ Areas (85% X Leaseable)	
Virginia:										
Alleghany	89	4	85	-1	0	- 3	81	69	59	66%
Bath	108	6	102	-2	0	- 3	97	82	70	65%
Buchanan	508	10	498	-3	-1	-15	479	407	346	68%
Dickenson	332	14	318	-5	0	-10	303	258	219	66%
Highland	83	6	77	-1	0	- 2	74	63	53	64%
Lee	219	10	209	-2	0	- 6	201	171	145	66%
Russell	48	1	47	-1	0	- 1	45	38	32	67%
Tazewell	157	2	155	-2	0	- 5	148	126	107	68%
Wise	371	10	361	-5	0	-11	345	293	249	67%
Total	1,915		1,852(97%)				1,773(93%)		1,280	(67%)
Tennessee:										
Campbell	338		(Assumed that 56% of the Shale area is the drillable area)						189	
Claiborne	89		"					"	50	
Fentress	498		"					"	279	
Morgan	270		"					"	151	
Overton	441		"					"	247	
Pickett	158		"					"	88	
Scott	544		"					"	305	
Total	2,338								1,309	(56%)

1/ Urban area consist of metro areas and rural towns.
2/ Assumes drilling in national forest areas.
3/ Other - R/W railroads, waterways, airports, golf courses, etc., which would not be considered potential leasable lands.
4/ Leaseable properties assume that 15% of potential lease lands cannot be leased because of landowner refusal, coal mining problems.
5/ Drillable areas assume that 15% of leaseable properties cannot be drilled due to bad title, landowner problems, lack of right of way access.

TABLE F-7

New York

Estimate of Drillable Areas by County

(Area in Square Miles)

County Name	Shale Area	Urban[1] (Estimated)	Total Rural Area	Less Storage Fields	Less State Parks Only	Less[2] Other (3%)	Potential Lease Lands	Leaseable[3] Properties (85% X Pot.)	Drillable[4] Areas (85% X Leaseable)	
Albany	263	29	234	0	- 6	- 7	221	188	160	61%
Allegany	1,047	44	1,003	- 2	0	-30	971	825	702	67%
Broome	714	60	654	0	- 3	-20	631	536	456	64%
Cattaraugus	1,318	45	1,273	-16	-96	-38	1,123	955	811	62%
Cayuga	419	40	379	0	- 3	-11	365	310	264	63%
Chautauqua	1,081	66	1,015	0	- 1	-30	984	836	711	66%
Chemung	415	24	391	0	- 1	-12	378	321	273	66%
Chenango	903	41	862	0	- 1	-26	835	710	603	67%
Cortland	502	30	472	0	0	-14	458	389	331	66%
Delaware	1,443	59	1,384	0	0	-41	1,343	1,142	970	67%
Erie	899	143	756	0	- 4	-23	729	620	527	59%
Genesee	276	26	250	0	- 3	- 8	239	203	173	63%
Greene	588	44	544	0	0	-16	528	449	381	65%
Herkimer	287	12	275	0	0	- 8	267	227	193	67%
Livingston	606	50	556	0	-11	-17	528	449	381	63%
Madison	198	25	173	0	- 1	- 5	167	142	121	61%
Monroe	14	2	12	0	0	- 0	12	10	9	62%
Oneida	122	13	109	0	- 4	- 3	102	87	74	60%
Onondaga	397	45	352	0	- 3	-11	338	287	244	62%
Ontario	553	40	513	0	- 1	-15	497	422	359	65%
Orange	42	5	37	0	0	- 1	36	31	26	62%
Otsego	1,013	50	963	0	0	-29	934	794	675	67%
Schoharie	530	36	494	0	0	-15	479	407	346	65%
Schuyler	330	26	304	- 6	- 1	- 9	288	245	208	63%
Seneca	250	24	226	0	- 3	- 7	216	184	156	62%
Steuben	1,410	66	1,344	-57	- 1	-40	1,246	1,059	900	64%
Sullivan	931	76	855	0	0	-26	829	705	599	64%
Tioga	524	27	497	0	0	-15	482	410	348	66%
Tompkins	482	32	450	0	- 4	-14	432	367	312	65%
Ulster	571	59	512	0	0	-15	497	422	359	63%
Wyoming	598	42	556	0	-12	-17	527	448	381	64%
Yates	343	21	332	6	- 1	-10	305	259	220	64%
Total	19,069		17,767(93%)				16,987(89%)		12,273	(64%)

1/ Urban areas consists of metro areas and rural towns.

2/ Other - R/W railroads, waterways, airports, golf courses, etc., which would not be considered potential leaseable lands.

3/ Leaseable properties assume that 15% of potential lease lands cannot be leased because of landowner refusal, coal mining problems.

4/ Drillable areas assume that 15% of leaseable properties cannot be drilled due to bad title, landowner problems lack of right of way access.

TABLE F-8

Eastern Kentucky
Estimate of Drillable Areas by County
(Area in Square Miles)

County Name	Total County Area	Number 1/ Shale Wells Drilled	Developed 2/ Shale Area	Potential 3/ Leaseable Lands	Drillable 4/ Shale Area
Bell	370	0	0	370	237
Boyd	159	33	13	146	93
Breathitt	494	0	0	494	316
Carter	397	0	0	397	254
Casey	435	0	0	435	278
Clay	474	0	0	474	303
Clinton	190	0	0	190	122
Elliott	240	0	0	240	154
Floyd	399	968	378	21	13
Greenup	351	0	0	351	225
Harlan	469	0	0	469	300
Jackson	337	0	0	337	216
Johnson	264	76	30	234	150
Knott	356	765	299	57	36
Knox	373	0	0	373	239
Laurel	446	0	0	446	285
Lawrence	425	66	26	399	255
Lee	210	0	0	210	134
Leslie	409	18	7	402	257
Letcher	339	183	71	268	172
Lincoln	340	0	0	340	218
McCreary	418	0	0	418	268
Magoffin	303	53	21	282	180
Martin	231	306	120	111	71
Menifee	210	0	0	210	134
Morgan	369	0	0	369	236
Owsley	197	0	0	197	126
Perry	341	335	131	210	134
Pike	782	902	352	430	275
Powell	173	0	0	173	111
Pulaski	653	0	0	653	418
Rockcastle	311	0	0	311	199
Russell	238	0	0	238	152
Wayne	440	0	0	440	282
Whitley	459	0	0	459	294
Wolfe	227	0	0	227	145
Total	12,829			11,381 (89%)	7,282 (57%)

1/ Total shale wells drilled per historical county data sheet compiled by task group.

2/ Developed shale area assumes an average of 250 acres leased per well drilled to account for non-drillable areas = Drilled Shale Wells X 250 acres per well ÷ 640 acres per square mile.

3/ Potential leaseable lands (undeveloped area) = Total county area - Developed shale area.

4/ Drillable shale area assumes that 64% of potential leaseable lands are drillable.

APPENDIX G

Computer Printout of Production Economics

COMPUTER PRINTOUT OF PRODUCTION ECONOMICS

ACRONYMS AND TERMINOLOGY

AN = Annual
AVE = Average
CUM = Cumulative
INV = Investment, Millions of Dollars
INVEST = Average Per-Well Investment Cost (Dollars)
PR = Price (Dollars per MMBtu)
PROD = 30-Year Cumulative Production (BCF)
RSA = Reserves Added (BCF)
RSR = Reserves Remaining (BCF)

TRADITIONAL TECHNOLOGY - ROR 10% (BASE CASE)

BASELINE DATA AS OF 05 SEP 79 2
FROM NPCGAS V 4.0 - 05 SEP 79   OF 09/11/79. 10.40.24.

AT ROR OF 10%

PRICE	RESERVE	AREA	CI	WELLS	PROD/W	AVE PR	INVEST
2.50	3330	3237	59	12679	262619	1.95	149500
3.50	5126	6022	51	22834	224003	2.94	197385
5.00	2970	4632	38	17600	168774	4.12	208214
7.00	3493	7145	29	27150	128658	6.11	233850
9.00	1660	4665	21	17727	93625	8.32	229242
500.00	8759	35219	14	137633	63642	16.92	321247
TOTAL	25338	62920		235674		6.57	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. TRADITIONAL TECHNOLOGY - LOW GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/11/79. 10.40.50.

AT ROR OF 10%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	8	0	0	0	0	0	8
		CUM	430	8	0	0	0	0	0	8
		RSA ANNUAL		113	0	0	0	0	0	113
		RSA CUM		113	0	0	0	0	0	113
		RSR		105	0	0	0	0	0	105
		INV								64
		INV CUM								64
1981	15	AN	478	16	0	0	0	0	0	16
		CUM	908	24	0	0	0	0	0	24
		RSA ANNUAL		126	0	0	0	0	0	126
		RSA CUM		238	0	0	0	0	0	238
		RSR		214	0	0	0	0	0	214
		INV								71
		INV CUM								136
1982	16	AN	541	24	0	0	0	0	0	24
		CUM	1449	48	0	0	0	0	0	48
		RSA ANNUAL		142	0	0	0	0	0	142
		RSA CUM		381	0	0	0	0	0	381
		RSR		333	0	0	0	0	0	333
		INV								81
		INV CUM								217
1983	18	AN	606	32	0	0	0	0	0	32
		CUM	2055	80	0	0	0	0	0	80
		RSA ANNUAL		159	0	0	0	0	0	159
		RSA CUM		540	0	0	0	0	0	540
		RSR		460	0	0	0	0	0	460
		INV								91
		INV CUM								307
1984	21	AN	682	41	0	0	0	0	0	41
		CUM	2737	121	0	0	0	0	0	121

		RSA ANNUAL		179	0	0	0	0	0	179
		RSA CUM		719	0	0	0	0	0	719
		RSR		598	0	0	0	0	0	598
		INV								
		INV CUM								102
										409
1985	23	AN	766	51	0	0	0	0	0	51
		CUM	3503	171	0	0	0	0	0	171
		RSA ANNUAL		201	0	0	0	0	0	201
		RSA CUM		920	0	0	0	0	0	920
		RSR		749	0	0	0	0	0	749
		INV								115
		INV CUM								524
1986	26	AN	858	61	0	0	0	0	0	61
		CUM	4362	233	0	0	0	0	0	233
		RSA ANNUAL		226	0	0	0	0	0	226
		RSA CUM		1146	0	0	0	0	0	1146
		RSR		913	0	0	0	0	0	913
		INV								123
		INV CUM								652
1987	29	AN	964	73	0	0	0	0	0	73
		CUM	5326	306	0	0	0	0	0	306
		RSA ANNUAL		253	0	0	0	0	0	253
		RSA CUM		1399	0	0	0	0	0	1399
		RSR		1093	0	0	0	0	0	1093
		INV								144
		INV CUM								796
1988	33	AN	1082	86	0	0	0	0	0	86
		CUM	6408	392	0	0	0	0	0	392
		RSA ANNUAL		284	0	0	0	0	0	284
		RSA CUM		1683	0	0	0	0	0	1683
		RSR		1291	0	0	0	0	0	1291
		INV								162
		INV CUM								958
1989	37	AN	1214	100	0	0	0	0	0	100
		CUM	7622	492	0	0	0	0	0	492
		RSA ANNUAL		319	0	0	0	0	0	319
		RSA CUM		2002	0	0	0	0	0	2002

		RSP		1509	0	0	0	0	0	1509
		INV								181
		INV CUM								1139
1990	41	AN	1352	116	0	0	0	0	0	116
		CUM	8984	609	0	0	0	0	0	609
		RSA ANNUAL		358	0	0	0	0	0	358
		RSA CUM		2359	0	0	0	0	0	2359
		RSR		1751	0	0	0	0	0	1751
		INV								204
		INV CUM								1343
1991	46	AN	1527	134	0	0	0	0	0	134
		CUM	10511	743	0	0	0	0	0	743
		RSA ANNUAL		401	0	0	0	0	0	401
		RSA CUM		2760	0	0	0	0	0	2760
		RSR		2017	0	0	0	0	0	2017
		INV								228
		INV CUM								1571
1992	52	AN	1713	154	0	0	0	0	0	154
		CUM	12224	897	0	0	0	0	0	897
		RSA ANNUAL		450	0	0	0	0	0	450
		RSA CUM		3210	0	0	0	0	0	3210
		RSR		2313	0	0	0	0	0	2313
		INV								256
		INV CUM								1827
1993	58	AN	1920	149	24	0	0	0	0	172
		CUM	14144	1046	24	0	0	0	0	1069
		RSA ANNUAL		120	328	0	0	0	0	448
		RSA CUM		3330	328	0	0	0	0	3658
		RSR		2284	304	0	0	0	0	2589
		INV								357
		INV CUM								2185
1994	65	AN	2152	137	55	0	0	0	0	192
		CUM	[illegible]	1183	78	0	0	0	0	1261
		RSA ANNUAL		0	432	0	0	0	0	482
		RSA CUM		3330	810	0	0	0	0	4140
		RSR		2147	732	0	0	0	0	2879
		INV								425

		INV CUM								2609
1995	73	AN	2412	129	85	0	0	0	0	214
		CUM	18708	1312	163	0	0	0	0	1475
		RSA ANNUAL		0	540	0	0	0	0	540
		RSA CUM		3330	1350	0	0	0	0	4680
		RSR		2018	1187	0	0	0	0	3205
		INV								475
		INV CUM								3085
1996	82	AN	2704	122	117	0	0	0	0	240
		CUM	21412	1434	281	0	0	0	0	1715
		RSA ANNUAL		0	606	0	0	0	0	606
		RSA CUM		3330	1956	0	0	0	0	5286
		RSR		1696	1576	0	0	0	0	3571
		INV								534
		INV CUM								3619
1997	92	AN	3031	117	151	0	0	0	0	268
		CUM	24443	1551	432	0	0	0	0	1983
		RSA ANNUAL		0	679	0	0	0	0	679
		RSA CUM		3330	2635	0	0	0	0	5965
		RSR		1779	2203	0	0	0	0	3952
		INV								598
		INV CUM								4218
1998	103	AN	3299	112	188	0	0	0	0	301
		CUM	27742	1664	620	0	0	0	0	2284
		RSA ANNUAL		0	761	0	0	0	0	761
		RSA CUM		3330	3397	0	0	0	0	6726
		RSR		1666	2776	0	0	0	0	4442
		INV								571
		INV CUM								4889
1999	115	AN	3908	108	229	0	0	0	0	337
		CUM	31650	1772	849	0	0	0	0	2621
		RSA ANNUAL		0	853	0	0	0	0	853
		RSA CUM		3330	4250	0	0	0	0	7579
		RSR		1558	3400	0	0	0	0	4958
		INV								752
		INV CUM								5640

2000	129	AN 4265	105	267	4	0	0	0	377
		CUM 35915	1877	1116	4	0	0	0	2999
		RSA ANNUAL	0	877	59	0	0	0	936
		RSA CUM	3330	5126	59	0	0	0	8515
		RSR	1453	4010	55	0	0	0	5518
		INV							846
		INV CUM							6486

DEFAULT GEDRSK = .95

B. TRADITIONAL TECHNOLOGY - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/11/79. 10.40.55.

AT ROR OF 10%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	15	0	0	0	0	0	15
		CUM	770	15	0	0	0	0	0	15
		RSA ANNUAL		202	0	0	0	0	0	202
		RSA CUM		202	0	0	0	0	0	202
		RSR		188	0	0	0	0	0	188
		INV								115
		INV CUM								115
1981	45	AN	1295	37	0	0	0	0	0	37
		CUM	2065	51	0	0	0	0	0	51
		RSA ANNUAL		340	0	0	0	0	0	340
		RSA CUM		542	0	0	0	0	0	542
		RSR		491	0	0	0	0	0	491
		INV								194
		INV CUM								309
1982	60	AN	1320	66	0	0	0	0	0	66
		CUM	3385	117	0	0	0	0	0	117
		RSA ANNUAL		478	0	0	0	0	0	478
		RSA CUM		1020	0	0	0	0	0	1020
		RSR		903	0	0	0	0	0	903
		INV								272
		INV CUM								581
1983	75	AN	2345	101	0	0	0	0	0	101
		CUM	5730	218	0	0	0	0	0	218
		RSA ANNUAL		616	0	0	0	0	0	616
		RSA CUM		1636	0	0	0	0	0	1636
		RSR		1419	0	0	0	0	0	1419
		INV								351
		INV CUM								931
1984	90	AN	2870	142	0	0	0	0	0	142
		CUM	8600	359	0	0	0	0	0	359

		RSA ANNUAL		754	0	0	0	0	0	754
		RSA CUM		2390	0	0	0	0	0	2390
		RSP		2030	0	0	0	0	0	2030
		INV								429
		INV CUM								1360
1985	105	AN	3325	188	0	0	0	0	0	188
		CUM	12495	548	0	0	0	0	0	548
		RSA ANNUAL		892	0	0	0	0	0	892
		RSA CUM		3281	0	0	0	0	0	3281
		RSP		2734	0	0	0	0	0	2734
		INV								508
		INV CUM								1868
1986	120	AN	3920	169	61	0	0	0	0	230
		CUM	16415	717	61	0	0	0	0	777
		RSA ANNUAL		48	837	0	0	0	0	885
		RSA CUM		3330	837	0	0	0	0	4167
		RSR		2613	776	0	0	0	0	3389
		INV								765
		INV CUM								2633
1987	135	AN	4445	154	122	0	0	0	0	276
		CUM	20860	871	183	0	0	0	0	1053
		RSA ANNUAL		0	996	0	0	0	0	996
		RSA CUM		3330	1833	0	0	0	0	5162
		RSR		2459	1650	0	0	0	0	4109
		INV								877
		INV CUM								3510
1988	150	AN	4970	143	184	0	0	0	0	327
		CUM	25830	1013	367	0	0	0	0	1380
		RSA ANNUAL		0	1113	0	0	0	0	1113
		RSA CUM		3330	2946	0	0	0	0	6276
		RSR		2316	2579	0	0	0	0	4895
		INV								981
		INV CUM								4491
1989	165	AN	5495	134	248	0	0	0	0	382
		CUM	31325	1148	615	0	0	0	0	1762
		RSA ANNUAL		0	1231	0	0	0	0	1231
		RSA CUM		3330	4177	0	0	0	0	7507

		RSR		2182	3562	0	0	0	0	5744
		INV								1085
		INV CUM								5576
1990	180	AN	6020	127	286	22	0	0	0	434
		CUM	37345	1275	900	22	0	0	0	2197
		RSA ANNUAL		0	949	301	0	0	0	1250
		RSA CUM		3330	5126	301	0	0	0	8757
		RSR		2055	4226	279	0	0	0	6560
		INV								1208
		INV CUM								6784
1991	195	AN	6545	121	254	98	0	0	0	473
		CUM	43890	1396	1154	120	0	0	0	2670
		RSA ANNUAL		0	0	1105	0	0	0	1105
		RSA CUM		3330	5126	1405	0	0	0	9861
		RSR		1934	3972	1286	0	0	0	7191
		INV								1363
		INV CUM								8146
1992	210	AN	7070	116	232	168	0	0	0	517
		CUM	50960	1512	1386	289	0	0	0	3187
		RSA ANNUAL		0	0	1193	0	0	0	1193
		RSA CUM		3330	5126	2599	0	0	0	11054
		RSR		1817	3740	2311	0	0	0	7868
		INV								1472
		INV CUM								9618
1993	225	AN	7505	112	216	171	50	0	0	549
		CUM	59555	1625	1603	459	50	0	0	3735
		RSA ANNUAL		0	0	372	694	0	0	1066
		RSA CUM		3330	5126	2970	694	0	0	12120
		RSR		1705	3524	2512	644	0	0	8384
		INV								1720
		INV CUM								11338
1994	240	AN	8120	108	204	151	117	0	0	580
		CUM	66575	1733	1806	610	167	0	0	4316
		RSA ANNUAL		0	0	0	1045	0	0	1045
		RSA CUM		3330	5126	2970	1738	0	0	13165
		RSR		1597	3320	2360	1571	0	0	9848
		INV								1899

		INV CUM								13237
1995	255	AN	8645	105	194	138	179	0	0	616
		CUM	75320	1838	2060	748	347	0	0	4932
		RSA ANNUAL		0	0	0	1112	0	0	1112
		RSA CUM		3330	5126	2970	2851	0	0	14277
		RSP		1492	3126	2223	2504	0	0	9345
		INV								2022
		INV CUM								15259
1996	270	AN	9170	102	135	128	201	28	0	645
		CUM	84490	1940	2195	876	548	28	0	5577
		RSA ANNUAL		0	0	0	642	391	0	1033
		RSA CUM		3330	5126	2970	3493	391	0	15310
		RSP		1390	2941	2094	2945	363	0	9733
		INV								2125
		INV CUM								17384
1997	285	AN	9635	99	178	120	178	89	0	664
		CUM	94125	2039	2363	997	726	117	0	6241
		RSA ANNUAL		0	0	0	0	908	0	908
		RSA CUM		3330	5126	2970	3493	1299	0	16218
		RSP		1291	2763	1974	2768	1181	0	9977
		INV								2223
		INV CUM								19606
1998	300	AN	10280	97	171	114	162	101	29	674
		CUM	104405	2135	2534	1111	888	218	29	6915
		RSA ANNUAL		0	0	0	0	361	405	766
		RSA CUM		3330	5126	2970	3493	1660	405	16984
		RSP		1194	2592	1860	2606	1441	376	10069
		INV								2928
		INV CUM								22535
1999	315	AN	10745	94	166	109	150	88	74	681
		CUM	115150	2230	2699	1220	1038	306	103	7597
		RSA ANNUAL		0	0	0	0	0	684	684
		RSA CUM		3330	5126	2970	3493	1660	1089	17668
		RSP		1100	2427	1751	2455	1353	986	10071
		INV								3452
		INV CUM								25986

2000	330	AN	11270	92	150	155	141	80	114	693
		CUM	125420	2322	2850	1324	1179	335	217	8289
		RSA	ANNUAL	0	0	0	0	0	717	717
		RSA	CUM	3330	5126	2970	3493	1660	1806	18385
		RSP		1008	2256	1646	2314	1274	1589	10096
		INV								3620
		INV	CUM							29607

TRADITIONAL TECHNOLOGY - ROR 15%

BASELINE DATA AS OF 05 SEP 79 2
FROM NPCGAS V 4.0 - 05 SEP 79   OF 09/11/79. 10.40.24.

AT ROR OF 15%

PRICE	RESERVE	AREA	C1	WELLS	PROD/W	AVE PR	INVEST
2.50	1857	1711	64	6503	285611	2.22	139184
3.50	2986	3537	50	13442	222148	3.18	157116
5.00	4588	5334	51	20271	226341	4.26	222113
7.00	2456	4188	35	15913	154329	5.91	205847
9.00	2628	5498	28	20891	125803	8.16	231742
500.00	10823	41751	15	158655	68217	20.22	309275
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TOTAL	25338	62020		235674		11.37	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. TRADITIONAL TECHNOLOGY - LOW GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/13/79. 05.40.21.

AT ROR OF 15%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	9	0	0	0	0	0	9
		CUM	430	9	0	0	0	0	0	9
		RSA ANNUAL		123	0	0	0	0	0	123
		RSA CUM		123	0	0	0	0	0	123
		RSP		114	0	0	0	0	0	114
		INV								60
		INV CUM								60
1981	15	AN	478	17	0	0	0	0	0	17
		CUM	908	26	0	0	0	0	0	26
		RSA ANNUAL		137	0	0	0	0	0	137
		RSA CUM		259	0	0	0	0	0	259
		RSP		233	0	0	0	0	0	233
		INV								67
		INV CUM								126
1982	16	AN	541	26	0	0	0	0	0	26
		CUM	1449	52	0	0	0	0	0	52
		RSA ANNUAL		155	0	0	0	0	0	155
		RSA CUM		414	0	0	0	0	0	414
		RSP		362	0	0	0	0	0	362
		INV								75
		INV CUM								202
1983	18	AN	606	35	0	0	0	0	0	35
		CUM	2055	87	0	0	0	0	0	87
		RSA ANNUAL		173	0	0	0	0	0	173
		RSA CUM		587	0	0	0	0	0	587
		RSP		500	0	0	0	0	0	500
		INV								84
		INV CUM								286
1984	21	AN	682	45	0	0	0	0	0	45
		CUM	2737	131	0	0	0	0	0	131

		RSA ANNUAL		195	0	0	0	0	0	195
		RSA CUM		782	0	0	0	0	0	782
		RSP		650	0	0	0	0	0	650
		INV								95
		INV CUM								381
1985	23	AN	766	55	0	0	0	0	0	55
		CUM	3503	186	0	0	0	0	0	186
		RSA ANNUAL		219	0	0	0	0	0	219
		RSA CUM		1000	0	0	0	0	0	1000
		RSP		814	0	0	0	0	0	814
		INV								107
		INV CUM								488
1986	26	AN	859	67	0	0	0	0	0	67
		CUM	4362	253	0	0	0	0	0	253
		RSA ANNUAL		245	0	0	0	0	0	245
		RSA CUM		1246	0	0	0	0	0	1246
		RSP		993	0	0	0	0	0	993
		INV								120
		INV CUM								607
1987	29	AN	964	79	0	0	0	0	0	79
		CUM	5326	333	0	0	0	0	0	333
		RSA ANNUAL		275	0	0	0	0	0	275
		RSA CUM		1521	0	0	0	0	0	1521
		RSP		1189	0	0	0	0	0	1189
		INV								134
		INV CUM								741
1988	33	AN	1082	94	0	0	0	0	0	94
		CUM	6408	426	0	0	0	0	0	426
		RSA ANNUAL		309	0	0	0	0	0	309
		RSA CUM		1830	0	0	0	0	0	1830
		RSP		1404	0	0	0	0	0	1404
		INV								151
		INV CUM								892
1989	37	AN	1214	86	18	0	0	0	0	104
		CUM	7622	512	18	0	0	0	0	530
		RSA ANNUAL		27	249	0	0	0	0	276
		RSA CUM		1857	249	0	0	0	0	2106

		RSP		1345	231	0	0	0	0	1576
		INV								189
		INV CUM								1081
1990	41	AN	1362	79	37	0	0	0	0	116
		CUM	8984	592	55	0	0	0	0	646
		RSA ANNUAL		0	303	0	0	0	0	303
		RSA CUM		1857	551	0	0	0	0	2408
		RSP		1266	496	0	0	0	0	1762
		INV								214
		INV CUM								1295
1991	46	AN	1527	74	56	0	0	0	0	130
		CUM	10511	666	110	0	0	0	0	776
		RSA ANNUAL		0	339	0	0	0	0	339
		RSA CUM		1857	890	0	0	0	0	2748
		RSP		1191	780	0	0	0	0	1971
		INV								240
		INV CUM								1535
1992	52	AN	1713	70	76	0	0	0	0	146
		CUM	12224	736	186	0	0	0	0	922
		RSA ANNUAL		0	381	0	0	0	0	381
		RSA CUM		1857	1271	0	0	0	0	3128
		RSP		1121	1085	0	0	0	0	2206
		INV								269
		INV CUM								1804
1993	58	AN	1920	67	97	0	0	0	0	164
		CUM	14144	804	283	0	0	0	0	1087
		RSA ANNUAL		0	427	0	0	0	0	427
		RSA CUM		1857	1698	0	0	0	0	3555
		RSP		1054	1414	0	0	0	0	2468
		INV								302
		INV CUM								2106
1994	65	AN	2152	64	120	0	0	0	0	184
		CUM	16296	868	403	0	0	0	0	1271
		RSA ANNUAL		0	478	0	0	0	0	478
		RSA CUM		1857	2176	0	0	0	0	4033
		RSP		989	1772	0	0	0	0	2762
		INV								338

		INV CUM									2444
1995	73	AM	2412	62	145	0	0	0	0		207
		CUM	18708	930	548	0	0	0	0		1478
		RSA ANNUAL		0	536	0	0	0	0		536
		RSA CUM		1857	2711	0	0	0	0		4569
		RSP		927	2163	0	0	0	0		3090
		INV									379
		INV CUM									2823
1996	82	AM	2704	60	150	24	0	0	0		234
		CUM	21412	990	698	24	0	0	0		1712
		RSA ANNUAL		0	275	332	0	0	0		607
		RSA CUM		1857	2986	332	0	0	0		5175
		RSP		867	2288	308	0	0	0		3464
		INV									520
		INV CUM									3343
1997	92	AM	3031	56	138	69	0	0	0		263
		CUM	24443	1048	834	94	0	0	0		1975
		RSA ANNUAL		0	0	686	0	0	0		686
		RSA CUM		1857	2986	1018	0	0	0		5861
		RSP		809	2152	925	0	0	0		3886
		INV									673
		INV CUM									4016
1998	103	AM	3399	56	126	114	0	0	0		296
		CUM	27842	1104	960	208	0	0	0		2272
		RSA ANNUAL		0	0	769	0	0	0		769
		RSA CUM		1857	2986	1787	0	0	0		6631
		RSP		753	2027	1580	0	0	0		4359
		INV									755
		INV CUM									4771
1999	115	AM	3808	55	118	160	0	0	0		334
		CUM	31650	1159	1078	368	0	0	0		2605
		RSA ANNUAL		0	0	862	0	0	0		862
		RSA CUM		1857	2986	2649	0	0	0		7493
		RSP		698	1908	2281	0	0	0		4887
		INV									846
		INV CUM									5617

2000	129	AN	4265	54	112	209	0	0	0	375
		CUM	35915	1213	1190	577	0	0	0	2981
		RSA ANNUAL		0	0	965	0	0	0	965
		RSA CUM		1857	2986	3615	0	0	0	8458
		RSP		644	1796	3037	0	0	0	5477
		INV								947
		INV CUM								6564

B. TRADITIONAL TECHNOLOGY - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79
09/13/79. 05.40.24.
AT ROR OF 15%
GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	16	0	0	0	0	0	16
		CUM	770	16	0	0	0	0	0	16
		RSA ANNUAL		220	0	0	0	0	0	220
		RSA CUM		220	0	0	0	0	0	220
		RSP		204	0	0	0	0	0	204
		INV								107
		INV CUM								107
1981	45	AN	1295	40	0	0	0	0	0	40
		CUM	2065	56	0	0	0	0	0	56
		RSA ANNUAL		370	0	0	0	0	0	370
		RSA CUM		590	0	0	0	0	0	590
		RSP		534	0	0	0	0	0	534
		INV								180
		INV CUM								287
1982	60	AN	1820	71	0	0	0	0	0	71
		CUM	3885	127	0	0	0	0	0	127
		RSA ANNUAL		520	0	0	0	0	0	520
		RSA CUM		1110	0	0	0	0	0	1110
		RSP		982	0	0	0	0	0	982
		INV								253
		INV CUM								541
1983	75	AN	2345	110	0	0	0	0	0	110
		CUM	6230	237	0	0	0	0	0	237
		RSA ANNUAL		670	0	0	0	0	0	670
		RSA CUM		1779	0	0	0	0	0	1779
		RSP		1543	0	0	0	0	0	1543
		INV								326
		INV CUM								867
1984	90	AN	2870	100	42	0	0	0	0	142
		CUM	9100	337	42	0	0	0	0	379

		RSA ANNUAL		78	577	0	0	0	0	655
		RSA CUM		1857	577	0	0	0	0	2434
		RSR		1520	535	0	0	0	0	2055
		INV								446
		INV CUM								1313
1985	105	AN	3395	90	89	0	0	0	0	179
		CUM	12495	427	131	0	0	0	0	558
		RSA ANNUAL		0	754	0	0	0	0	754
		RSA CUM		1857	1331	0	0	0	0	3188
		RSR		1430	1200	0	0	0	0	2630
		INV								533
		INV CUM								1847
1986	120	AN	3920	83	138	0	0	0	0	222
		CUM	16415	511	269	0	0	0	0	780
		RSA ANNUAL		0	871	0	0	0	0	871
		RSA CUM		1857	2202	0	0	0	0	4059
		RSR		1347	1933	0	0	0	0	3279
		INV								616
		INV CUM								2462
1987	135	AN	4445	76	176	15	0	0	0	269
		CUM	20860	588	445	15	0	0	0	1049
		RSA ANNUAL		0	784	207	0	0	0	991
		RSA CUM		1857	2986	207	0	0	0	5051
		RSR		1269	2541	192	0	0	0	4002
		INV								758
		INV CUM								3220
1988	150	AN	4970	73	154	94	0	0	0	321
		CUM	25830	661	600	109	0	0	0	1370
		RSA ANNUAL		0	0	1125	0	0	0	1125
		RSA CUM		1857	2986	1332	0	0	0	6175
		RSR		1196	2386	1223	0	0	0	4805
		INV								1104
		INV CUM								4324
1989	165	AN	5495	70	140	168	0	0	0	378
		CUM	31325	731	740	277	0	0	0	1748
		RSA ANNUAL		0	0	1244	0	0	0	1244
		RSA CUM		1857	2986	2576	0	0	0	7419

		RSP		1126	2246	2299	0	0	0	5671
		INV								1221
		INV CUM								5545
1990	180	AN	6020	67	130	242	0	0	0	439
		CUM	37345	798	870	519	0	0	0	2187
		RSA ANNUAL		0	0	1363	0	0	0	1363
		RSA CUM		1857	2986	3938	0	0	0	8782
		RSP		1059	2116	3419	0	0	0	6595
		INV								1337
		INV CUM								6882
1991	195	AN	6545	64	122	257	41	0	0	484
		CUM	43890	862	992	776	41	0	0	2671
		RSA ANNUAL		0	0	650	567	0	0	1217
		RSA CUM		1857	2986	4588	567	0	0	9999
		RSP		995	1994	3812	526	0	0	7328
		INV								1394
		INV CUM								8276
1992	210	AN	7070	62	115	228	113	0	0	519
		CUM	50960	924	1107	1004	154	0	0	3189
		RSA ANNUAL		0	0	0	1091	0	0	1091
		RSA CUM		1857	2986	4588	1658	0	0	11090
		RSP		934	1879	3584	1504	0	0	7900
		INV								1455
		INV CUM								9731
1993	225	AN	7595	60	110	209	153	22	0	554
		CUM	58555	983	1217	1214	307	22	0	3743
		RSA ANNUAL		0	0	0	798	305	0	1103
		RSA CUM		1857	2986	4588	2456	305	0	12193
		RSP		874	1769	3374	2149	283	0	8449
		INV								1626
		INV CUM								11357
1994	240	AN	8120	58	105	195	132	92	0	583
		CUM	66675	1041	1323	1408	439	114	0	4326
		RSA ANNUAL		0	0	0	0	1022	0	1022
		RSA CUM		1857	2986	4588	2456	1327	0	13214
		RSP		816	1663	3180	2017	1213	0	8888
		INV								1882

		INV CUM							13239
1995	255	AN	9645	56	102	163	119	156	0	616
		CUM	75220	1098	1424	1592	558	270	0	4942
		RSA ANNUAL		0	0	0	0	1088	0	1088
		RSA CUM		1857	2986	4588	2456	2414	0	14302
		RSP		760	1562	2996	1898	2144	0	9359
		INV								2003
		INV CUM								15243
1996	270	AN	9270	55	98	174	110	149	37	623
		CUM	84490	1153	1522	1766	668	419	37	5565
		RSA ANNUAL		0	0	0	0	214	510	723
		RSA CUM		1857	2986	4588	2456	2628	510	15025
		RSP		705	1454	2622	1788	2209	473	9460
		INV								2704
		INV CUM								17947
1997	285	AN	9695	54	95	166	103	132	78	628
		CUM	94185	1206	1617	1932	771	551	115	6193
		RSA ANNUAL		0	0	0	0	0	661	661
		RSA CUM		1857	2986	4588	2456	2628	1171	15686
		RSP		651	1369	2656	1685	2077	1056	9493
		INV								2998
		INV CUM								20945
1998	300	AN	10220	52	92	160	97	121	117	639
		CUM	104405	1258	1710	2092	868	673	232	6833
		RSA ANNUAL		0	0	0	0	0	697	697
		RSA CUM		1857	2986	4588	2456	2628	1868	16384
		RSP		599	1277	2496	1588	1956	1636	9551
		INV								3161
		INV CUM								24106
1999	315	AN	10745	51	90	154	92	113	154	654
		CUM	115150	1309	1799	2246	960	785	386	7485
		RSA ANNUAL		0	0	0	0	0	733	733
		RSA CUM		1857	2986	4588	2456	2628	2601	17117
		RSP		548	1187	2342	1495	1843	2215	9630
		INV								3323
		INV CUM								27429

2000	330	AN	11270	50	87	149	88	106	190	671
		CUM	126420	1359	1886	2395	1049	891	576	8157
		RSA ANNUAL		0	0	0	0	0	769	769
		RSA CUM		1857	2986	4588	2456	2628	3370	17885
		RSP		498	1100	2193	1407	1737	2794	9728
		INV								3486
		INV CUM								30915

TRADITIONAL TECHNOLOGY - ROR 20%

BASELINE DATA AS OF 05 SEP 79 2
FROM NRGGAS V 4.0 - 05 SEP 79 OF 09/11/79. 10.40.24.

AT ROR OF 20%

PRICE	RESERVE	AREA	CI	WELLS	PROD/W	AVE PR	INVEST
2.50	256	179	65	679	377350	2.37	164266
3.50	1838	1834	60	6970	263685	2.86	133247
5.00	4332	5060	51	19228	225293	4.27	174849
7.00	3699	4682	47	17793	207682	5.76	221912
9.00	2221	4032	33	15322	144986	7.86	205600
500.00	12992	46232	17	175682	73951	22.71	302840
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TOTAL	25338	62020		235674		14.14	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. TRADITIONAL TECHNOLOGY - LOW GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/13/79. 05.42.45.

AT ROR OF 20%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	12	0	0	0	0	0	12
		CUM	430	12	0	0	0	0	0	12
		RSA ANNUAL		162	0	0	0	0	0	162
		RSA CUM		162	0	0	0	0	0	162
		RSP		151	0	0	0	0	0	151
		INV								71
		INV CUM								71
1981	15	AN	478	17	4	0	0	0	0	21
		CUM	908	28	4	0	0	0	0	33
		RSA ANNUAL		94	60	0	0	0	0	154
		RSA CUM		256	60	0	0	0	0	317
		RSP		228	56	0	0	0	0	284
		INV								71
		INV CUM								142
1982	16	AN	541	14	14	0	0	0	0	28
		CUM	1449	42	18	0	0	0	0	61
		RSA ANNUAL		0	143	0	0	0	0	143
		RSA CUM		256	203	0	0	0	0	459
		RSP		214	185	0	0	0	0	399
		INV								72
		INV CUM								214
1983	18	AN	606	13	23	0	0	0	0	36
		CUM	2055	55	42	0	0	0	0	97
		RSA ANNUAL		0	160	0	0	0	0	160
		RSA CUM		256	363	0	0	0	0	619
		RSP		201	321	0	0	0	0	522
		INV								81
		INV CUM								295
1984	21	AN	682	12	33	0	0	0	0	45
		CUM	2737	67	75	0	0	0	0	141

		RSA ANNUAL		0	180	0	0	0	0	180
		RSA CUM		256	543	0	0	0	0	799
		RSP		190	468	0	0	0	0	658
		INV								91
		INV CUM								386
1985	23	AN	766	11	43	0	0	0	0	54
		CUM	3503	78	118	0	0	0	0	195
		RSA ANNUAL		0	202	0	0	0	0	202
		RSA CUM		256	745	0	0	0	0	1001
		RSP		179	627	0	0	0	0	805
		INV								102
		INV CUM								488
1986	26	AN	859	10	54	0	0	0	0	65
		CUM	4362	88	172	0	0	0	0	260
		RSA ANNUAL		0	227	0	0	0	0	227
		RSA CUM		256	971	0	0	0	0	1227
		RSP		168	799	0	0	0	0	967
		INV								114
		INV CUM								602
1987	29	AN	964	10	67	0	0	0	0	76
		CUM	5326	98	239	0	0	0	0	336
		RSA ANNUAL		0	254	0	0	0	0	254
		RSA CUM		256	1225	0	0	0	0	1482
		RSP		159	987	0	0	0	0	1145
		INV								128
		INV CUM								731
1988	33	AN	1082	9	80	0	0	0	0	89
		CUM	6408	107	319	0	0	0	0	426
		RSA ANNUAL		0	285	0	0	0	0	285
		RSA CUM		256	1511	0	0	0	0	1767
		RSP		149	1192	0	0	0	0	1341
		INV								144
		INV CUM								875
1989	37	AN	1214	9	95	0	0	0	0	104
		CUM	7622	116	413	0	0	0	0	529
		RSA ANNUAL		0	320	0	0	0	0	320
		RSA CUM		256	1831	0	0	0	0	2087

		R SP		140	1418	0	0	0	0	1558
		INV								162
		INV CUM								1037
1990	41	AN	1362	9	85	22	0	0	0	116
		CUM	8984	125	499	22	0	0	0	645
		RSA ANNUAL		0	7	301	0	0	0	308
		RSA CUM		256	1838	301	0	0	0	2395
		R SP		132	1339	279	0	0	0	1750
		INV								237
		INV CUM								1274
1991	46	AN	1527	8	79	43	0	0	0	130
		CUM	10511	133	577	65	0	0	0	775
		RSA ANNUAL		0	0	344	0	0	0	344
		RSA CUM		256	1838	645	0	0	0	2739
		R SP		123	1260	580	0	0	0	1964
		INV								267
		INV CUM								1541
1992	52	AN	1713	8	74	64	0	0	0	146
		CUM	12224	141	651	129	0	0	0	921
		RSA ANNUAL		0	0	386	0	0	0	386
		RSA CUM		256	1838	1031	0	0	0	3125
		R SP		115	1187	902	0	0	0	2204
		INV								300
		INV CUM								1840
1993	58	AN	1920	8	70	87	0	0	0	165
		CUM	14144	149	721	216	0	0	0	1086
		RSA ANNUAL		0	0	433	0	0	0	433
		RSA CUM		256	1838	1463	0	0	0	3557
		R SP		108	1117	1247	0	0	0	2472
		INV								336
		INV CUM								2176
1994	65	AN	2152	8	67	111	0	0	0	185
		CUM	16296	156	788	327	0	0	0	1271
		RSA ANNUAL		0	0	485	0	0	0	485
		RSA CUM		256	1838	1948	0	0	0	4042
		R SP		100	1050	1621	0	0	0	2771
		INV								376

		INV CUM								2552
1995	73	AN	2412	7	64	137	0	0	0	209
		CUM	18708	164	852	464	0	0	0	1480
		RSA ANNUAL		0	0	543	0	0	0	543
		RSA CUM		256	1838	2491	0	0	0	4585
		RSR		92	986	2027	0	0	0	3106
		INV								422
		INV CUM								2974
1996	82	AN	2704	7	62	166	0	0	0	235
		CUM	21412	171	913	630	0	0	0	1715
		RSA ANNUAL		0	0	609	0	0	0	609
		RSA CUM		256	1838	3101	0	0	0	5195
		RSR		85	924	2471	0	0	0	3480
		INV								473
		INV CUM								3447
1997	92	AN	3031	7	59	198	0	0	0	264
		CUM	24443	178	973	828	0	0	0	1979
		RSA ANNUAL		0	0	683	0	0	0	683
		RSA CUM		256	1838	3783	0	0	0	5878
		RSR		78	865	2956	0	0	0	3899
		INV								530
		INV CUM								3977
1998	103	AN	3399	7	58	217	15	0	0	296
		CUM	27842	185	1031	1044	15	0	0	2274
		RSA ANNUAL		0	0	548	201	0	0	749
		RSA CUM		256	1838	4332	201	0	0	6627
		RSR		71	807	3288	186	0	0	4352
		INV								640
		INV CUM								4616
1999	115	AN	3808	7	56	196	69	0	0	328
		CUM	31650	192	1086	1240	84	0	0	2603
		RSA ANNUAL		0	0	0	792	0	0	792
		RSA CUM		256	1838	4332	992	0	0	7418
		RSR		64	751	3092	908	0	0	4816
		INV								845
		INV CUM								5461

2000	129	AN	4265	7	54	182	122	0	0	365
		CUM	35915	199	1141	1422	206	0	0	2968
		FSA	ANNUAL	0	0	0	887	0	0	887
		RSA	CUM	256	1838	4332	1879	0	0	8305
		R SP		58	697	2910	1673	0	0	5337
		INV								946
		INV	CUM							6408

B. TRADITIONAL TECHNOLOGY - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/13/79. 05.42.48.

AT ROR OF 20%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	19	2	0	0	0	0	20
		CUM	770	19	2	0	0	0	0	20
		RSA ANNUAL		256	24	0	0	0	0	280
		RSA CUM		256	24	0	0	0	0	280
		RSP		238	22	0	0	0	0	260
		INV								124
		INV CUM								124
1981	45	AN	1295	15	26	0	0	0	0	41
		CUM	2065	34	28	0	0	0	0	62
		RSA ANNUAL		0	341	0	0	0	0	341
		RSA CUM		256	365	0	0	0	0	622
		RSP		222	338	0	0	0	0	560
		INV								173
		INV CUM								296
1982	60	AN	1820	13	56	0	0	0	0	70
		CUM	3885	47	84	0	0	0	0	132
		RSA ANNUAL		0	480	0	0	0	0	480
		RSA CUM		256	845	0	0	0	0	1102
		RSP		209	761	0	0	0	0	970
		INV								243
		INV CUM								539
1983	75	AN	2345	12	93	0	0	0	0	105
		CUM	6230	60	177	0	0	0	0	236
		RSA ANNUAL		0	618	0	0	0	0	618
		RSA CUM		256	1464	0	0	0	0	1720
		RSP		197	1287	0	0	0	0	1484
		INV								312
		INV CUM								851
1984	90	AN	2870	11	107	24	0	0	0	142
		CUM	9100	71	284	24	0	0	0	378

		RSA ANNUAL		0	374	327	0	0	0	701
		RSA CUM		256	1838	327	0	0	0	2421
		RSP		185	1554	303	0	0	0	2043
		INV								443
		INV CUM								1294
1985	105	AN	3295	11	94	75	0	0	0	180
		CUM	12495	82	378	99	0	0	0	558
		RSA ANNUAL		0	0	765	0	0	0	765
		RSA CUM		256	1838	1092	0	0	0	3186
		RSP		175	1460	993	0	0	0	2628
		INV								594
		INV CUM								1888
1986	120	AN	3920	10	86	127	0	0	0	223
		CUM	16415	92	453	225	0	0	0	780
		RSA ANNUAL		0	0	883	0	0	0	883
		RSA CUM		256	1838	1975	0	0	0	4069
		RSP		165	1375	1749	0	0	0	3289
		INV								685
		INV CUM								2573
1987	135	AN	4445	10	79	181	0	0	0	270
		CUM	20860	101	543	407	0	0	0	1050
		RSA ANNUAL		0	0	1001	0	0	0	1001
		RSA CUM		256	1838	2976	0	0	0	5071
		RSP		155	1295	2570	0	0	0	4020
		INV								777
		INV CUM								3350
1988	150	AN	4970	9	75	238	0	0	0	322
		CUM	25830	110	617	645	0	0	0	1373
		RSA ANNUAL		0	0	1120	0	0	0	1120
		RSA CUM		256	1838	4096	0	0	0	6190
		RSP		146	1221	3451	0	0	0	4818
		INV								869
		INV CUM								4219
1989	165	AN	5495	9	71	226	67	0	0	373
		CUM	31325	119	688	871	67	0	0	1745
		RSA ANNUAL		0	0	236	925	0	0	1161
		RSA CUM		256	1838	4332	925	0	0	7351

		RSP		137	1150	3460	858	0	0	5605
		INV								1170
		INV CUM								5389
1990	180	AN	6020	9	57	205	146	0	0	426
		CUM	27345	128	755	1076	213	0	0	2172
		RSA ANNUAL		0	0	0	1251	0	0	1251
		RSA CUM		256	1838	4332	2176	0	0	8602
		RSP		129	1082	3256	1963	0	0	6430
		INV								1336
		INV CUM								6725
1991	195	AN	6545	8	65	189	222	0	0	484
		CUM	43890	136	820	1265	435	0	0	2656
		RSA ANNUAL		0	0	0	1361	0	0	1361
		RSA CUM		256	1838	4332	3537	0	0	9963
		RSP		120	1018	3067	3102	0	0	7307
		INV								1452
		INV CUM								8178
1992	210	AN	7070	8	62	177	203	66	0	517
		CUM	50960	144	882	1442	638	66	0	3173
		RSA ANNUAL		0	0	0	162	912	0	1074
		RSA CUM		256	1838	4332	3699	912	0	11037
		RSP		112	956	2890	3061	846	0	7864
		INV								1466
		INV CUM								9644
1993	225	AN	7595	8	60	168	182	134	0	552
		CUM	58555	152	943	1610	820	200	0	3724
		RSA ANNUAL		0	0	0	0	1101	0	1101
		RSA CUM		256	1838	4332	3699	2013	0	12138
		RSP		105	895	2722	2879	1813	0	8414
		INV								1562
		INV CUM								11205
1994	240	AN	8120	8	58	160	167	129	36	558
		CUM	66675	159	1001	1770	987	329	36	4282
		RSA ANNUAL		0	0	0	0	208	494	703
		RSA CUM		256	1838	4332	3699	2221	494	12841
		RSP		97	837	2562	2712	1892	458	8559
		INV								2319

		INV CUM								13525
1995	255	AN	8645	7	57	153	156	114	76	563
		CUM	75320	167	1057	1923	1143	443	112	4845
		RSA ANNUAL		0	0	0	0	0	639	639
		RSA CUM		256	1838	4332	3699	2221	1133	13480
		RSP		90	781	2409	2555	1778	1022	8635
		INV								2618
		INV CUM								16143
1996	270	AN	9170	7	55	147	147	104	113	574
		CUM	84490	174	1112	2070	1291	547	225	5419
		RSA ANNUAL		0	0	0	0	0	678	678
		RSA CUM		256	1838	4332	3699	2221	1812	14158
		RSP		83	726	2262	2408	1674	1587	8739
		INV								2777
		INV CUM								18920
1997	285	AN	9695	7	54	142	140	97	150	589
		CUM	94185	181	1166	2212	1431	644	375	6008
		RSA ANNUAL		0	0	0	0	0	717	717
		RSA CUM		256	1838	4332	3699	2221	2529	14875
		RSP		75	672	2119	2268	1578	2154	8867
		INV								2936
		INV CUM								21856
1998	300	AN	10220	7	52	138	134	91	186	607
		CUM	104405	188	1218	2350	1564	734	560	6615
		RSA ANNUAL		0	0	0	0	0	756	756
		RSA CUM		256	1838	4332	3699	2221	3284	15631
		RSP		69	620	1982	2135	1487	2724	9016
		INV								3095
		INV CUM								24951
1999	315	AN	10745	7	51	134	128	86	222	628
		CUM	115150	195	1270	2484	1693	820	782	7243
		RSA ANNUAL		0	0	0	0	0	795	795
		RSA CUM		256	1838	4332	3699	2221	4079	16425
		RSP		62	568	1848	2006	1401	3297	9183
		INV								3254
		INV CUM								28205

2000	330	AN	11270	7	50	130	124	82	258	650
		CUM	126420	201	1320	2614	1816	902	1040	7893
		RSA	ANNUAL	0	0	0	0	0	833	833
		RSA	CUM	256	1838	4332	3699	2221	4912	17259
		RSP		55	518	1718	1882	1319	3873	9366
		INV								3413
		INV	CUM							31618

CONVENTIONAL TECHNOLOGY - ROR 10% (BASE CASE)

BASELINE DATA AS OF 05 SEP 79 2
FROM NPCGAS V 4.0 - 05 SEP 79 OF 09/10/79. 09.55.02.

			AT	ROR OF	10%		
PRICE	RESERVE	AREA	C1	WELLS	PROD/W	AVE PR	INVEST
2.50	7261	6223	69	23649	307018	2.01	183231
3.50	7256	6911	62	26260	276312	2.98	252572
5.00	4927	6414	46	24371	202153	4.43	272552
7.00	4071	7120	34	27057	150473	6.03	269084
9.00	3480	9038	23	34346	101314	8.25	240381
500.00	10389	26313	23	99991	103902	13.59	428684
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TOTAL	37384	62020		235674		6.75	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. CONVENTIONAL TECHNOLOGY - LOW GROWTH
DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79
09/10/79. 09.55.25.
AT ROR OF 10%
GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	10	0	0	0	0	0	10
		CUM	430	10	0	0	0	0	0	10
		RSA ANNUAL		132	0	0	0	0	0	132
		RSA CUM		132	0	0	0	0	0	132
		RSR		122	0	0	0	0	0	122
		INV								79
		INV CUM								79
1981	15	AN	478	19	0	0	0	0	0	19
		CUM	908	28	0	0	0	0	0	28
		RSA ANNUAL		147	0	0	0	0	0	147
		RSA CUM		279	0	0	0	0	0	279
		RSR		251	0	0	0	0	0	251
		INV								88
		INV CUM								166
1982	16	AN	541	28	0	0	0	0	0	28
		CUM	1449	56	0	0	0	0	0	56
		RSA ANNUAL		166	0	0	0	0	0	166
		RSA CUM		445	0	0	0	0	0	445
		RSR		389	0	0	0	0	0	389
		INV								99
		INV CUM								266
1983	18	AN	606	37	0	0	0	0	0	37
		CUM	2055	93	0	0	0	0	0	93
		RSA ANNUAL		186	0	0	0	0	0	186
		RSA CUM		631	0	0	0	0	0	631
		RSR		538	0	0	0	0	0	538
		INV								111
		INV CUM								377
1984	21	AN	682	48	0	0	0	0	0	48
		CUM	2737	141	0	0	0	0	0	141

		RSA ANNUAL		209	0	0	0	0	0	209
		RSA CUM		840	0	0	0	0	0	840
		RSR		699	0	0	0	0	0	699
		INV								125
		INV CUM								502
1985	23	AN	766	59	0	0	0	0	0	59
		CUM	3503	200	0	0	0	0	0	200
		RSA ANNUAL		235	0	0	0	0	0	235
		RSA CUM		1075	0	0	0	0	0	1075
		RSR		875	0	0	0	0	0	875
		INV								140
		INV CUM								642
1986	26	AN	859	72	0	0	0	0	0	72
		CUM	4362	272	0	0	0	0	0	272
		RSA ANNUAL		264	0	0	0	0	0	264
		RSA CUM		1339	0	0	0	0	0	1339
		RSR		1067	0	0	0	0	0	1067
		INV								157
		INV CUM								799
1987	29	AN	964	85	0	0	0	0	0	85
		CUM	5326	357	0	0	0	0	0	357
		RSA ANNUAL		296	0	0	0	0	0	296
		RSA CUM		1635	0	0	0	0	0	1635
		RSR		1278	0	0	0	0	0	1278
		INV								177
		INV CUM								976
1988	33	AN	1082	101	0	0	0	0	0	101
		CUM	6408	458	0	0	0	0	0	458
		RSA ANNUAL		332	0	0	0	0	0	332
		RSA CUM		1967	0	0	0	0	0	1967
		RSR		1509	0	0	0	0	0	1509
		INV								198
		INV CUM								1174
1989	37	AN	1214	117	0	0	0	0	0	117
		CUM	7622	575	0	0	0	0	0	575
		RSA ANNUAL		373	0	0	0	0	0	373
		RSA CUM		2340	0	0	0	0	0	2340

		RSR		1765	0	0	0	0	0	1765
		INV								222
		INV CUM								1397
1990	41	AN	1362	136	0	0	0	0	0	136
		CUM	8984	712	0	0	0	0	0	712
		RSA ANNUAL		418	0	0	0	0	0	418
		RSA CUM		2758	0	0	0	0	0	2758
		RSR		2047	0	0	0	0	0	2047
		INV								250
		INV CUM								1646
1991	46	AN	1527	157	0	0	0	0	0	157
		CUM	10511	869	0	0	0	0	0	869
		RSA ANNUAL		469	0	0	0	0	0	469
		RSA CUM		3227	0	0	0	0	0	3227
		RSR		2359	0	0	0	0	0	2359
		INV								280
		INV CUM								1926
1992	52	AN	1713	180	0	0	0	0	0	180
		CUM	12224	1049	0	0	0	0	0	1049
		RSA ANNUAL		526	0	0	0	0	0	526
		RSA CUM		3753	0	0	0	0	0	3753
		RSR		2704	0	0	0	0	0	2704
		INV								314
		INV CUM								2240
1993	58	AN	1920	206	0	0	0	0	0	206
		CUM	14144	1255	0	0	0	0	0	1255
		RSA ANNUAL		589	0	0	0	0	0	589
		RSA CUM		4342	0	0	0	0	0	4342
		RSR		3087	0	0	0	0	0	3087
		INV								352
		INV CUM								2592
1994	65	AN	2152	235	0	0	0	0	0	235
		CUM	16296	1490	0	0	0	0	0	1490
		RSA ANNUAL		661	0	0	0	0	0	661
		RSA CUM		5003	0	0	0	0	0	5003
		RSR		3513	0	0	0	0	0	3513
		INV								394

		INV CUM								2986
1995	73	AN	2412	268	0	0	0	0	0	268
		CUM	18708	1758	0	0	0	0	0	1758
		RSA ANNUAL		741	0	0	0	0	0	741
		RSA CUM		5744	0	0	0	0	0	5744
		RSR		3986	0	0	0	0	0	3986
		INV								442
		INV CUM								3428
1996	82	AN	2704	304	0	0	0	0	0	304
		CUM	21412	2061	0	0	0	0	0	2061
		RSA ANNUAL		830	0	0	0	0	0	830
		RSA CUM		6574	0	0	0	0	0	6574
		RSR		4513	0	0	0	0	0	4513
		INV								495
		INV CUM								3923
1997	92	AN	3031	327	16	0	0	0	0	342
		CUM	24443	2388	16	0	0	0	0	2404
		RSA ANNUAL		687	219	0	0	0	0	906
		RSA CUM		7261	219	0	0	0	0	7480
		RSR		4873	203	0	0	0	0	5076
		INV								610
		INV CUM								4534
1998	103	AN	3399	299	81	0	0	0	0	380
		CUM	27842	2687	97	0	0	0	0	2784
		RSA ANNUAL		0	939	0	0	0	0	939
		RSA CUM		7261	1159	0	0	0	0	8419
		RSR		4573	1062	0	0	0	0	5635
		INV								858
		INV CUM								5392
1999	115	AN	3808	280	144	0	0	0	0	424
		CUM	31650	2968	241	0	0	0	0	3208
		RSA ANNUAL		0	1052	0	0	0	0	1052
		RSA CUM		7261	2211	0	0	0	0	9471
		RSR		4293	1970	0	0	0	0	6263
		INV								962
		INV CUM								6354

2000	129	AN	4265	266	208	0	0	0	0	474
		CUM	35915	3233	449	0	0	0	0	3682
		RSA ANNUAL		0	1178	0	0	0	0	1178
		RSA CUM		7261	3389	0	0	0	0	10650
		RSR		4027	2940	0	0	0	0	6968
		INV								1077
		INV CUM								7431

DEFAULT GEORSK = .95

B. CONVENTIONAL TECHNOLOGY - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/10/79. 09.55.28.

AT ROR OF 10 %

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	17	0	0	0	0	0	17
		CUM	770	17	0	0	0	0	0	17
		RSA ANNUAL		236	0	0	0	0	0	236
		RSA CUM		236	0	0	0	0	0	236
		RSR		219	0	0	0	0	0	219
		INV								141
		INV CUM								141
1981	45	AN	1295	43	0	0	0	0	0	43
		CUM	2065	60	0	0	0	0	0	60
		RSA ANNUAL		398	0	0	0	0	0	398
		RSA CUM		634	0	0	0	0	0	634
		RSR		574	0	0	0	0	0	574
		INV								237
		INV CUM								378
1982	60	AN	1820	77	0	0	0	0	0	77
		CUM	3885	137	0	0	0	0	0	137
		RSA ANNUAL		559	0	0	0	0	0	559
		RSA CUM		1193	0	0	0	0	0	1193
		RSR		1056	0	0	0	0	0	1056
		INV								333
		INV CUM								712
1983	75	AN	2345	118	0	0	0	0	0	118
		CUM	6230	254	0	0	0	0	0	254
		RSA ANNUAL		720	0	0	0	0	0	720
		RSA CUM		1913	0	0	0	0	0	1913
		RSR		1658	0	0	0	0	0	1658
		INV								430
		INV CUM								1142
1984	90	AN	2870	166	0	0	0	0	0	166
		CUM	9100	420	0	0	0	0	0	420

		RSA ANNUAL		881	0	0	0	0	0	881
		RSA CUM		2794	0	0	0	0	0	2794
		RSR		2374	0	0	0	0	0	2374
		INV								526
		INV CUM								1667
1985	105	AN	3395	220	0	0	0	0	0	220
		CUM	12495	640	0	0	0	0	0	640
		RSA ANNUAL		1042	0	0	0	0	0	1042
		RSA CUM		3836	0	0	0	0	0	3836
		RSR		3196	0	0	0	0	0	3196
		INV								622
		INV CUM								2289
1986	120	AN	3920	281	0	0	0	0	0	281
		CUM	16415	921	0	0	0	0	0	921
		RSA ANNUAL		1204	0	0	0	0	0	1204
		RSA CUM		5040	0	0	0	0	0	5040
		RSR		4119	0	0	0	0	0	4119
		INV								718
		INV CUM								3008
1987	135	AN	4445	347	0	0	0	0	0	347
		CUM	20860	1268	0	0	0	0	0	1268
		RSA ANNUAL		1365	0	0	0	0	0	1365
		RSA CUM		6404	0	0	0	0	0	6404
		RSR		5136	0	0	0	0	0	5136
		INV								814
		INV CUM								3822
1988	150	AN	4970	371	44	0	0	0	0	414
		CUM	25830	1639	44	0	0	0	0	1683
		RSA ANNUAL		856	603	0	0	0	0	1459
		RSA CUM		7261	603	0	0	0	0	7863
		RSR		5622	559	0	0	0	0	6181
		INV								1062
		INV CUM								4884
1989	165	AN	5495	335	146	0	0	0	0	481
		CUM	31325	1974	189	0	0	0	0	2163
		RSA ANNUAL		0	1518	0	0	0	0	1518
		RSA CUM		7261	2121	0	0	0	0	9382

		RSR		5287	1931	0	0	0	0	7218
		INV								1388
		INV CUM								6272
1990	180	AN	6020	310	243	0	0	0	0	553
		CUM	37345	2284	432	0	0	0	0	2716
		RSA ANNUAL		0	1663	0	0	0	0	1663
		RSA CUM		7261	3784	0	0	0	0	11045
		RSR		4977	3352	0	0	0	0	8329
		INV								1520
		INV CUM								7792
1991	195	AN	6545	291	339	0	0	0	0	630
		CUM	43890	2574	771	0	0	0	0	3346
		RSA ANNUAL		0	1808	0	0	0	0	1808
		RSA CUM		7261	5593	0	0	0	0	12854
		RSR		4686	4821	0	0	0	0	9508
		INV								1653
		INV CUM								9446
1992	210	AN	7070	276	415	15	0	0	0	706
		CUM	50960	2850	1187	15	0	0	0	4052
		RSA ANNUAL		0	1663	212	0	0	0	1876
		RSA CUM		7261	7256	212	0	0	0	14729
		RSR		4411	6069	197	0	0	0	10677
		INV								1807
		INV CUM								11252
1993	225	AN	7595	263	366	124	0	0	0	753
		CUM	58555	3113	1553	139	0	0	0	4805
		RSA ANNUAL		0	0	1535	0	0	0	1535
		RSA CUM		7261	7256	1748	0	0	0	16264
		RSR		4148	5703	1609	0	0	0	11459
		INV								2070
		INV CUM								13322
1994	240	AN	8120	252	334	222	0	0	0	808
		CUM	66675	3365	1888	361	0	0	0	5613
		RSA ANNUAL		0	0	1641	0	0	0	1641
		RSA CUM		7261	7255	3389	0	0	0	17906
		RSR		3896	5369	3028	0	0	0	12293
		INV								2213

		INV CUM								15535
1995	255	AN	8645	243	311	300	11	0	0	865
		CUM	75320	3608	2198	661	11	0	0	6479
		RSA ANNUAL		0	0	1538	156	0	0	1694
		RSA CUM		7261	7256	4927	156	0	0	19600
		RSR		3653	5058	4265	145	0	0	13121
		INV								2353
		INV CUM								17888
1996	270	AN	9170	235	292	261	109	0	0	897
		CUM	84490	3843	2490	923	120	0	0	7376
		RSA ANNUAL		0	0	0	1380	0	0	1380
		RSA CUM		7261	7256	4927	1536	0	0	20980
		RSR		3418	4766	4004	1416	0	0	13604
		INV								2468
		INV CUM								20355
1997	285	AN	9695	227	277	236	196	0	0	937
		CUM	94185	4070	2767	1159	317	0	0	8313
		RSA ANNUAL		0	0	0	1459	0	0	1459
		RSA CUM		7261	7256	4927	2995	0	0	22439
		RSR		3191	4489	3768	2678	0	0	14126
		INV								2609
		INV CUM								22964
1998	300	AN	10220	221	264	218	245	22	0	971
		CUM	104405	4291	3032	1377	562	22	0	9284
		RSA ANNUAL		0	0	0	1076	311	0	1387
		RSA CUM		7261	7256	4927	4071	311	0	23826
		RSR		2970	4224	3550	3509	288	0	14542
		INV								2662
		INV CUM								25626
1999	315	AN	10745	215	254	204	214	97	0	984
		CUM	115150	4506	3285	1581	776	120	0	10269
		RSA ANNUAL		0	0	0	0	1089	0	1089
		RSA CUM		7261	7256	4927	4071	1399	0	24914
		RSR		2755	3971	3346	3295	1280	0	14646
		INV								2583
		INV CUM								28209

2000	330	AN	11270	210	244	193	194	164	0	1005
		CUM	126420	4716	3530	1774	970	284	0	11274
		RSA	ANNUAL	0	0	0	0	1142	0	1142
		RSA	CUM	7261	7256	4927	4071	2541	0	26056
		RSR		2545	3726	3152	3101	2257	0	14782
		INV								2709
		INV	CUM							30918

CONVENTIONAL TECHNOLOGY - ROR 15%

BASELINE DATA AS OF 05 SEP 79 2
FROM NPCGAS V 4.0 - 05 SEP 79 OF 09/10/79. 09.55.02.

AT ROR OF 15 %

PRICE	RESERVE	AREA	C1	WELLS	PROD/W	AVE PR	INVEST
2.50	2770	2231	74	8480	326701	2.29	160272
3.50	5796	5172	67	19653	294932	3.03	202612
5.00	6666	6555	60	24909	267634	4.15	256939
7.00	4668	6370	44	24206	192859	6.14	270681
9.00	3068	5408	34	20549	150257	7.98	268406
500.00	14395	36284	24	137878	104403	16.04	378601
	------	------		------		======	
TOTAL	37364	62020		235674		8.98	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. CONVENTIONAL TECHNOLOGY - LOW GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/10/79. 10.04.25.

AT ROR OF 15 %

YEAR	RIGS		WELLS	GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU) 2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	10	0	0	0	0	0	10
		CUM	430	10	0	0	0	0	0	10
		RSA ANNUAL		140	0	0	0	0	0	140
		RSA CUM		140	0	0	0	0	0	140
		RSR		130	0	0	0	0	0	130
		INV								69
		INV CUM								69
1981	15	AN	478	20	0	0	0	0	0	20
		CUM	908	30	0	0	0	0	0	30
		RSA ANNUAL		156	0	0	0	0	0	156
		RSA CUM		297	0	0	0	0	0	297
		RSR		267	0	0	0	0	0	267
		INV								77
		INV CUM								146
1982	16	AN	541	30	0	0	0	0	0	30
		CUM	1449	59	0	0	0	0	0	59
		RSA ANNUAL		177	0	0	0	0	0	177
		RSA CUM		473	0	0	0	0	0	473
		RSR		414	0	0	0	0	0	414
		INV								87
		INV CUM								232
1983	18	AN	606	40	0	0	0	0	0	40
		CUM	2055	99	0	0	0	0	0	99
		RSA ANNUAL		198	0	0	0	0	0	198
		RSA CUM		671	0	0	0	0	0	671
		RSR		572	0	0	0	0	0	572
		INV								97
		INV CUM								329
1984	21	AN	682	51	0	0	0	0	0	51
		CUM	2737	150	0	0	0	0	0	150

		RSA ANNUAL		223	0	0	0	0	0	223
		RSA CUM		894	0	0	0	0	0	894
		RSR		744	0	0	0	0	0	744
		INV								109
		INV CUM								439
1985	23	AN	766	63	0	0	0	0	0	63
		CUM	3503	213	0	0	0	0	0	213
		RSA ANNUAL		250	0	0	0	0	0	250
		RSA CUM		1144	0	0	0	0	0	1144
		RSR		931	0	0	0	0	0	931
		INV								123
		INV CUM								561
1986	26	AN	859	76	0	0	0	0	0	76
		CUM	4362	289	0	0	0	0	0	289
		RSA ANNUAL		281	0	0	0	0	0	281
		RSA CUM		1425	0	0	0	0	0	1425
		RSR		1136	0	0	0	0	0	1136
		INV								138
		INV CUM								699
1987	29	AN	964	91	0	0	0	0	0	91
		CUM	5326	380	0	0	0	0	0	380
		RSA ANNUAL		315	0	0	0	0	0	315
		RSA CUM		1740	0	0	0	0	0	1740
		RSR		1360	0	0	0	0	0	1360
		INV								155
		INV CUM								854
1988	33	AN	1082	107	0	0	0	0	0	107
		CUM	6408	487	0	0	0	0	0	487
		RSA ANNUAL		353	0	0	0	0	0	353
		RSA CUM		2093	0	0	0	0	0	2093
		RSR		1606	0	0	0	0	0	1606
		INV								173
		INV CUM								1027
1989	37	AN	1214	125	0	0	0	0	0	125
		CUM	7622	612	0	0	0	0	0	612
		RSA ANNUAL		397	0	0	0	0	0	397
		RSA CUM		2490	0	0	0	0	0	2490

		RSR		1878	0	0	0	0	0	1878
		INV								195
		INV CUM								1222
1990	41	AN	1362	133	11	0	0	0	0	144
		CUM	8984	745	11	0	0	0	0	756
		RSA ANNUAL		280	149	0	0	0	0	429
		RSA CUM		2770	149	0	0	0	0	2919
		RSR		2025	138	0	0	0	0	2163
		INV								240
		INV CUM								1461
1991	46	AN	1527	121	41	0	0	0	0	163
		CUM	10511	866	52	0	0	0	0	919
		RSA ANNUAL		0	450	0	0	0	0	450
		RSA CUM		2770	599	0	0	0	0	3369
		RSR		1904	547	0	0	0	0	2451
		INV								309
		INV CUM								1771
1992	52	AN	1713	113	71	0	0	0	0	184
		CUM	12224	979	124	0	0	0	0	1103
		RSA ANNUAL		0	505	0	0	0	0	505
		RSA CUM		2770	1104	0	0	0	0	3875
		RSR		1791	981	0	0	0	0	2772
		INV								347
		INV CUM								2118
1993	58	AN	1920	106	102	0	0	0	0	208
		CUM	14144	1086	226	0	0	0	0	1311
		RSA ANNUAL		0	566	0	0	0	0	566
		RSA CUM		2770	1671	0	0	0	0	4441
		RSR		1685	1445	0	0	0	0	3130
		INV								389
		INV CUM								2507
1994	65	AN	2152	101	135	0	0	0	0	236
		CUM	16296	1187	360	0	0	0	0	1547
		RSA ANNUAL		0	635	0	0	0	0	635
		RSA CUM		2770	2305	0	0	0	0	5076
		RSR		1584	1945	0	0	0	0	3529
		INV								436

		INV CUM								2943
1995	73	AN	2412	97	170	0	0	0	0	266
		CUM	18708	1284	530	0	0	0	0	1813
		RSA ANNUAL		0	711	0	0	0	0	711
		RSA CUM		2770	3017	0	0	0	0	5787
		RSR		1487	2487	0	0	0	0	3974
		INV								489
		INV CUM								3431
1996	82	AN	2704	93	208	0	0	0	0	301
		CUM	21412	1377	737	0	0	0	0	2114
		RSA ANNUAL		0	797	0	0	0	0	797
		RSA CUM		2770	3814	0	0	0	0	6584
		RSR		1393	3077	0	0	0	0	4470
		INV								548
		INV CUM								3979
1997	92	AN	3031	90	249	0	0	0	0	339
		CUM	24443	1467	987	0	0	0	0	2453
		RSA ANNUAL		0	894	0	0	0	0	894
		RSA CUM		2770	4708	0	0	0	0	7478
		RSR		1303	3721	0	0	0	0	5025
		INV								614
		INV CUM								4593
1998	103	AN	3399	87	296	0	0	0	0	383
		CUM	27842	1554	1282	0	0	0	0	2836
		RSA ANNUAL		0	1002	0	0	0	0	1002
		RSA CUM		2770	5711	0	0	0	0	8481
		RSR		1216	4428	0	0	0	0	5645
		INV								689
		INV CUM								5282
1999	115	AN	3808	85	271	68	0	0	0	424
		CUM	31650	1639	1554	68	0	0	0	3260
		RSA ANNUAL		0	86	941	0	0	0	1027
		RSA CUM		2770	5796	941	0	0	0	9508
		RSR		1132	4243	873	0	0	0	6248
		INV								963
		INV CUM								6245

2000	129	AN	4265	82	250	139	0	0	0	471
		CUM	35915	1721	1804	207	0	0	0	3731
		RSA ANNUAL		0	0	1141	0	0	0	1141
		RSA CUM		2770	5796	2083	0	0	0	10649
		RSR		1049	3993	1876	0	0	0	6918
		INV								1096
		INV CUM								7341

B. CONVENTIONAL TECHNOLOGY - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/10/79. 10.04.30.

AT ROR OF 15%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	18	0	0	0	0	0	18
		CUM	770	18	0	0	0	0	0	18
		RSA ANNUAL		252	0	0	0	0	0	252
		RSA CUM		252	0	0	0	0	0	252
		RSR		233	0	0	0	0	0	233
		INV								123
		INV CUM								123
1981	45	AN	1295	46	0	0	0	0	0	46
		CUM	2065	64	0	0	0	0	0	64
		RSA ANNUAL		423	0	0	0	0	0	423
		RSA CUM		675	0	0	0	0	0	675
		RSR		611	0	0	0	0	0	611
		INV								208
		INV CUM								331
1982	60	AN	1820	82	0	0	0	0	0	82
		CUM	3885	145	0	0	0	0	0	145
		RSA ANNUAL		595	0	0	0	0	0	595
		RSA CUM		1269	0	0	0	0	0	1269
		RSR		1124	0	0	0	0	0	1124
		INV								292
		INV CUM								623
1983	75	AN	2345	125	0	0	0	0	0	125
		CUM	6230	271	0	0	0	0	0	271
		RSA ANNUAL		766	0	0	0	0	0	766
		RSA CUM		2035	0	0	0	0	0	2035
		RSR		1765	0	0	0	0	0	1765
		INV								376
		INV CUM								998
1984	90	AN	2870	162	13	0	0	0	0	175
		CUM	9100	432	13	0	0	0	0	446

		RSA ANNUAL		735	183	0	0	0	0	918
		RSA CUM		2770	183	0	0	0	0	2953
		RSR		2338	170	0	0	0	0	2508
		INV								486
		INV CUM								1485
1985	105	AN	3395	142	83	0	0	0	0	225
		CUM	12495	574	97	0	0	0	0	671
		RSA ANNUAL		0	1001	0	0	0	0	1001
		RSA CUM		2770	1184	0	0	0	0	3955
		RSR		2196	1088	0	0	0	0	3284
		INV								688
		INV CUM								2173
1986	120	AN	3920	129	153	0	0	0	0	282
		CUM	16415	703	250	0	0	0	0	953
		RSA ANNUAL		0	1156	0	0	0	0	1156
		RSA CUM		2770	2340	0	0	0	0	5111
		RSR		2067	2091	0	0	0	0	4158
		INV								794
		INV CUM								2967
1987	135	AN	4445	120	225	0	0	0	0	345
		CUM	20860	823	475	0	0	0	0	1298
		RSA ANNUAL		0	1311	0	0	0	0	1311
		RSA CUM		2770	3651	0	0	0	0	6422
		RSR		1947	3176	0	0	0	0	5123
		INV								901
		INV CUM								3867
1988	150	AN	4970	112	301	0	0	0	0	414
		CUM	25830	935	777	0	0	0	0	1712
		RSA ANNUAL		0	1466	0	0	0	0	1466
		RSA CUM		2770	5117	0	0	0	0	7887
		RSR		1835	4341	0	0	0	0	6175
		INV								1007
		INV CUM								4874
1989	165	AN	5495	107	313	62	0	0	0	481
		CUM	31325	1042	1090	62	0	0	0	2193
		RSA ANNUAL		0	679	854	0	0	0	1533
		RSA CUM		2770	5796	854	0	0	0	9421

		RSR		1728	4707	793	0	0	0	7228
		INV								1287
		INV CUM								6161
1990	180	AN	6020	102	280	168	0	0	0	550
		CUM	37345	1144	1370	229	0	0	0	2743
		RSA ANNUAL		0	0	1611	0	0	0	1611
		RSA CUM		2770	5796	2466	0	0	0	11032
		RSR		1627	4426	2236	0	0	0	8289
		INV								1547
		INV CUM								7708
1991	195	AN	6545	97	258	268	0	0	0	623
		CUM	43890	1241	1628	498	0	0	0	3366
		RSA ANNUAL		0	0	1752	0	0	0	1752
		RSA CUM		2770	5796	4217	0	0	0	12784
		RSR		1529	4168	3720	0	0	0	9417
		INV								1682
		INV CUM								9390
1992	210	AN	7070	94	241	367	0	0	0	702
		CUM	50960	1335	1869	865	0	0	0	4068
		RSA ANNUAL		0	0	1892	0	0	0	1892
		RSA CUM		2770	5796	6109	0	0	0	14676
		RSR		1436	3927	5245	0	0	0	10608
		INV								1817
		INV CUM								11206
1993	225	AN	7595	91	228	361	77	0	0	756
		CUM	58555	1425	2096	1225	77	0	0	4824
		RSA ANNUAL		0	0	557	1063	0	0	1620
		RSA CUM		2770	5796	6666	1063	0	0	16296
		RSR		1345	3700	5441	986	0	0	11472
		INV								2027
		INV CUM								13233
1994	240	AN	8120	88	216	323	177	0	0	805
		CUM	66675	1513	2313	1549	254	0	0	5629
		RSA ANNUAL		0	0	0	1566	0	0	1566
		RSA CUM		2770	5796	6665	2629	0	0	17862
		RSR		1257	3483	5117	2376	0	0	12234
		INV								2198

		INV CUM								15431
1995	255	AN	8645	85	207	298	270	0	0	860
		CUM	75320	1598	2520	1847	524	0	0	6489
		RSA ANNUAL		0	0	0	1667	0	0	1667
		RSA CUM		2770	5796	6666	4297	0	0	19530
		RSR		1172	3276	4820	3773	0	0	13041
		INV								2340
		INV CUM								17771
1996	270	AN	9170	83	199	278	260	79	0	899
		CUM	84490	1681	2719	2125	784	79	0	7387
		RSA ANNUAL		0	0	0	372	1088	0	1460
		RSA CUM		2770	5796	6666	4668	1088	0	20990
		RSR		1089	3077	4542	3884	1010	0	13602
		INV								2466
		INV CUM								20237
1997	285	AN	9695	81	192	263	232	170	0	938
		CUM	94185	1762	2911	2387	1016	249	0	8325
		RSA ANNUAL		0	0	0	0	1457	0	1457
		RSA CUM		2770	5796	6666	4668	2545	0	22446
		RSR		1009	2885	4279	3652	2296	0	14121
		INV								2602
		INV CUM								22839
1998	300	AN	10220	79	186	250	213	184	50	961
		CUM	104405	1841	3097	2637	1229	433	50	9286
		RSA ANNUAL		0	0	0	0	543	690	1233
		RSA CUM		2770	5796	6666	4668	3088	690	23679
		RSR		930	2700	4029	3440	2655	640	14393
		INV								3471
		INV CUM								26311
1999	315	AN	10745	77	180	239	198	161	122	978
		CUM	115150	1918	3277	2876	1427	594	172	10264
		RSA ANNUAL		0	0	0	0	0	1122	1122
		RSA CUM		2770	5796	6666	4668	3088	1812	24801
		RSR		853	2519	3701	3241	2493	1639	14537
		INV								4068
		INV CUM								30379

2000	330	AN	11270	75	175	230	187	146	189	1002
		CUM	126420	1993	3452	3105	1614	740	361	11266
		RSA	ANNUAL	0	0	0	0	0	1177	1177
		RSA	CUM	2770	5796	6666	4668	3088	2968	25977
		RSR		777	2344	3561	3055	2347	2628	14712
		INV								4267
		INV	CUM							34646

CONVENTIONAL TECHNOLOGY - ROR 20%

BASELINE DATA AS OF 05 SEP 79 2
FROM NPCGAS V 4.0 - 05 SEP 79 OF 09/10/79. 09.55.02.

AT ROR OF 20 %

PRICE	RESERVE	AREA	C1	WELLS	PROD/W	AVE PR	INVEST
2.50	281	179	93	679	413068	2.50	192454
3.50	4349	3813	68	14490	300124	3.02	163122
5.00	6478	5633	68	21407	302611	4.21	236197
7.00	5542	6162	53	23416	236684	5.79	252410
9.00	3964	5537	43	21040	198386	8.17	281246
500.00	16771	40695	24	154642	108448	18.62	366207
	------	------		------		======	
TOTAL	37384	62020		235674		11.19	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. CONVENTIONAL TECHNOLOGY - LOW GROWTH
DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79
09/10/79. 10.06.03.
AT ROR OF 20%
GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	13	0	0	0	0	0	13
		CUM	430	13	0	0	0	0	0	13
		RSA ANNUAL		178	0	0	0	0	0	178
		RSA CUM		178	0	0	0	0	0	178
		RSR		165	0	0	0	0	0	165
		INV								83
		INV CUM								83
1981	15	AN	478	18	5	0	0	0	0	23
		CUM	908	31	5	0	0	0	0	36
		RSA ANNUAL		103	69	0	0	0	0	172
		RSA CUM		281	69	0	0	0	0	349
		RSR		250	64	0	0	0	0	313
		INV								85
		INV CUM								168
1982	16	AN	541	16	16	0	0	0	0	31
		CUM	1449	46	21	0	0	0	0	67
		RSA ANNUAL		0	162	0	0	0	0	162
		RSA CUM		281	231	0	0	0	0	512
		RSR		234	210	0	0	0	0	444
		INV								88
		INV CUM								256
1983	18	AN	606	14	26	0	0	0	0	40
		CUM	2055	60	47	0	0	0	0	108
		RSA ANNUAL		0	182	0	0	0	0	182
		RSA CUM		281	413	0	0	0	0	693
		RSR		220	366	0	0	0	0	586
		INV								99
		INV CUM								355
1984	21	AN	682	13	38	0	0	0	0	50
		CUM	2737	73	85	0	0	0	0	158

		RSA ANNUAL		0	205	0	0	0	0	205
		RSA CUM		281	618	0	0	0	0	898
		RSR		207	533	0	0	0	0	740
		INV								111
		INV CUM								466
1985	23	AN	766	12	49	0	0	0	0	61
		CUM	3503	85	134	0	0	0	0	219
		RSA ANNUAL		0	230	0	0	0	0	230
		RSA CUM		281	847	0	0	0	0	1128
		RSR		196	713	0	0	0	0	909
		INV								125
		INV CUM								591
1986	26	AN	859	11	62	0	0	0	0	73
		CUM	4362	96	196	0	0	0	0	292
		RSA ANNUAL		0	258	0	0	0	0	258
		RSA CUM		281	1105	0	0	0	0	1386
		RSR		184	909	0	0	0	0	1094
		INV								140
		INV CUM								731
1987	29	AN	964	11	76	0	0	0	0	86
		CUM	5326	107	272	0	0	0	0	379
		RSA ANNUAL		0	289	0	0	0	0	289
		RSA CUM		281	1395	0	0	0	0	1675
		RSR		174	1123	0	0	0	0	1297
		INV								157
		INV CUM								889
1988	33	AN	1082	10	91	0	0	0	0	101
		CUM	6408	117	363	0	0	0	0	480
		RSA ANNUAL		0	325	0	0	0	0	325
		RSA CUM		281	1719	0	0	0	0	2000
		RSR		163	1357	0	0	0	0	1520
		INV								176
		INV CUM								1065
1989	37	AN	1214	10	108	0	0	0	0	117
		CUM	7622	127	470	0	0	0	0	597
		RSA ANNUAL		0	364	0	0	0	0	364
		RSA CUM		281	2084	0	0	0	0	2364

		RSP		154	1613	0	0	0	0	1767
		INV								198
		INV CUM								1263
1990	41	AN	1362	9	126	0	0	0	0	136
		CUM	8984	136	596	0	0	0	0	733
		RSA ANNUAL		0	409	0	0	0	0	409
		RSA CUM		281	2492	0	0	0	0	2773
		RSR		144	1896	0	0	0	0	2040
		INV								222
		INV CUM								1485
1991	46	AN	1527	9	147	0	0	0	0	156
		CUM	10511	146	743	0	0	0	0	889
		RSA ANNUAL		0	458	0	0	0	0	458
		RSA CUM		281	2951	0	0	0	0	3231
		RSR		135	2207	0	0	0	0	2343
		INV								249
		INV CUM								1735
1992	52	AN	1713	9	170	0	0	0	0	179
		CUM	12224	154	913	0	0	0	0	1067
		RSA ANNUAL		0	514	0	0	0	0	514
		RSA CUM		281	3465	0	0	0	0	3745
		RSR		126	2552	0	0	0	0	2678
		INV								279
		INV CUM								2014
1993	58	AN	1920	9	195	0	0	0	0	204
		CUM	14144	163	1108	0	0	0	0	1271
		RSA ANNUAL		0	576	0	0	0	0	576
		RSA CUM		281	4041	0	0	0	0	4322
		RSR		118	2933	0	0	0	0	3050
		INV								313
		INV CUM								2327
1994	65	AN	2152	8	199	25	0	0	0	232
		CUM	16296	171	1308	25	0	0	0	1504
		RSA ANNUAL		0	308	341	0	0	0	649
		RSA CUM		281	4349	341	0	0	0	4970
		RSR		109	3041	316	0	0	0	3467
		INV								433

		INV CUM								2760
1995	73	AN	2412	8	183	73	0	0	0	264
		CUM	18708	179	1491	98	0	0	0	1768
		RSA ANNUAL		0	0	730	0	0	0	730
		RSA CUM		281	4349	1071	0	0	0	5700
		RSR		101	2858	973	0	0	0	3932
		INV								570
		INV CUM								3330
1996	82	AN	2704	8	171	121	0	0	0	300
		CUM	21412	187	1662	219	0	0	0	2068
		RSA ANNUAL		0	0	818	0	0	0	818
		RSA CUM		281	4349	1883	0	0	0	6513
		RSR		93	2687	1670	0	0	0	4450
		INV								639
		INV CUM								3969
1997	92	AN	3031	8	162	170	0	0	0	340
		CUM	24443	195	1824	389	0	0	0	2408
		RSA ANNUAL		0	0	917	0	0	0	917
		RSA CUM		281	4349	2806	0	0	0	7436
		RSR		85	2525	2418	0	0	0	5028
		INV								716
		INV CUM								4685
1998	103	AN	3399	8	155	222	0	0	0	385
		CUM	27842	203	1979	611	0	0	0	2793
		RSA ANNUAL		0	0	1029	0	0	0	1029
		RSA CUM		281	4349	3835	0	0	0	8464
		RSR		78	2370	3224	0	0	0	5672
		INV								803
		INV CUM								5488
1999	115	AN	3808	7	149	279	0	0	0	435
		CUM	31650	210	2127	890	0	0	0	3227
		RSA ANNUAL		0	0	1152	0	0	0	1152
		RSA CUM		281	4349	4987	0	0	0	9617
		RSR		70	2222	4097	0	0	0	6389
		INV								899
		INV CUM								6387

2000	129	AN	4265	7	143	340	0	0	0	490
		CUM	35915	218	2270	1230	0	0	0	3718
		RSA ANNUAL		0	0	1291	0	0	0	1291
		RSA CUM		281	4349	6278	0	0	0	10907
		RSR		63	2078	5048	0	0	0	7189
		INV								1007
		INV CUM								7394

B. CONVENTIONAL TECHNOLOGY - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/10/79. 10.06.06.

AT ROR OF 20 %

YEAR	RIGS		WELLS	GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU) 2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	20	2	0	0	0	0	22
		CUM	770	20	2	0	0	0	0	22
		RSA ANNUAL		281	27	0	0	0	0	308
		RSA CUM		281	27	0	0	0	0	308
		RSR		260	25	0	0	0	0	286
		INV								146
		INV CUM								146
1981	45	AN	1295	17	30	0	0	0	0	47
		CUM	2065	37	32	0	0	0	0	69
		RSA ANNUAL		0	389	0	0	0	0	389
		RSA CUM		281	416	0	0	0	0	696
		RSR		244	384	0	0	0	0	628
		INV								211
		INV CUM								357
1982	60	AN	1820	15	64	0	0	0	0	79
		CUM	3885	52	96	0	0	0	0	148
		RSA ANNUAL		0	546	0	0	0	0	546
		RSA CUM		281	962	0	0	0	0	1243
		RSR		229	866	0	0	0	0	1095
		INV								297
		INV CUM								654
1983	75	AN	2345	13	105	0	0	0	0	119
		CUM	6230	65	201	0	0	0	0	267
		RSA ANNUAL		0	704	0	0	0	0	704
		RSA CUM		281	1666	0	0	0	0	1946
		RSR		215	1465	0	0	0	0	1680
		INV								383
		INV CUM								1036
1984	90	AN	2870	12	153	0	0	0	0	165
		CUM	9100	78	354	0	0	0	0	432

		RSA	ANNUAL	0	861	0	0	0	0	861
		RSA	CUM	281	2527	0	0	0	0	2808
		RSR		203	2173	0	0	0	0	2376
		INV								468
		INV	CUM							1504
1985	105	AN	3395	12	207	0	0	0	0	218
		CUM	12495	89	561	0	0	0	0	650
		RSA	ANNUAL	0	1019	0	0	0	0	1019
		RSA	CUM	281	3546	0	0	0	0	3827
		RSR		191	2985	0	0	0	0	3176
		INV								554
		INV	CUM							2058
1986	120	AN	3920	11	239	27	0	0	0	278
		CUM	16415	100	800	27	0	0	0	928
		RSA	ANNUAL	0	803	377	0	0	0	1180
		RSA	CUM	281	4349	377	0	0	0	5006
		RSR		180	3548	350	0	0	0	4078
		INV								730
		INV	CUM							2789
1987	135	AN	4445	10	213	120	0	0	0	343
		CUM	20860	111	1013	147	0	0	0	1271
		RSA	ANNUAL	0	0	1345	0	0	0	1345
		RSA	CUM	281	4349	1722	0	0	0	6351
		RSR		170	3336	1575	0	0	0	5080
		INV								1050
		INV	CUM							3838
1988	150	AN	4970	10	195	209	0	0	0	414
		CUM	25830	121	1208	356	0	0	0	1686
		RSA	ANNUAL	0	0	1504	0	0	0	1504
		RSA	CUM	281	4349	3226	0	0	0	7855
		RSR		160	3140	2870	0	0	0	6170
		INV								1174
		INV	CUM							5012
1989	165	AN	5495	10	182	299	0	0	0	491
		CUM	31325	131	1390	655	0	0	0	2176
		RSA	ANNUAL	0	0	1663	0	0	0	1663
		RSA	CUM	281	4349	4889	0	0	0	9518

		RSR		150	2958	4233	0	0	0	7342
		INV								1298
		INV CUM								6310
1990	180	AN	6020	9	172	375	13	0	0	569
		CUM	37345	140	1562	1030	13	0	0	2745
		RSA ANNUAL		0	0	1589	182	0	0	1771
		RSA CUM		281	4349	6478	182	0	0	11289
		RSR		141	2787	5448	169	0	0	8544
		INV								1434
		INV CUM								7745
1991	195	AN	6545	9	163	330	123	0	0	625
		CUM	43890	149	1725	1360	136	0	0	3370
		RSA ANNUAL		0	0	0	1549	0	0	1549
		RSA CUM		281	4349	6478	1731	0	0	12838
		RSR		132	2624	5118	1595	0	0	9469
		INV								1652
		INV CUM								9397
1992	210	AN	7070	9	156	300	223	0	0	688
		CUM	50960	158	1881	1660	359	0	0	4058
		RSA ANNUAL		0	0	0	1673	0	0	1673
		RSA CUM		281	4349	6478	3404	0	0	14512
		RSR		123	2468	4818	3045	0	0	10454
		INV								1785
		INV CUM								11181
1993	225	AN	7595	8	150	279	320	0	0	758
		CUM	58555	166	2031	1939	680	0	0	4816
		RSA ANNUAL		0	0	0	1798	0	0	1798
		RSA CUM		281	4349	6478	5202	0	0	16309
		RSR		115	2318	4539	4522	0	0	11494
		INV								1917
		INV CUM								13098
1994	240	AN	8120	8	144	262	302	91	0	808
		CUM	66675	174	2176	2201	982	91	0	5624
		RSA ANNUAL		0	0	0	340	1259	0	1599
		RSA CUM		281	4349	6478	5542	1259	0	17909
		RSR		106	2173	4277	4560	1168	0	12285
		INV								2242

		INV CUM								15341
1995	255	AN	8645	8	140	248	271	193	0	660
		CUM	75320	182	2315	2449	1253	284	0	6484
		RSA ANNUAL		0	0	0	0	1629	0	1629
		RSA CUM		281	4349	6478	5542	2887	0	19537
		RSR		98	2034	4029	4289	2603	0	13053
		INV								2431
		INV CUM								17772
1996	270	AN	9170	8	136	237	249	242	27	898
		CUM	84490	190	2451	2686	1503	526	27	7383
		RSA ANNUAL		0	0	0	0	1076	375	1451
		RSA CUM		281	4349	6478	5542	3964	375	20988
		RSR		90	1898	3792	4040	3438	348	13606
		INV								2873
		INV CUM								20645
1997	285	AN	9695	8	132	227	233	210	98	908
		CUM	94185	198	2583	2913	1735	736	126	8291
		RSA ANNUAL		0	0	0	0	0	1051	1051
		RSA CUM		281	4349	6478	5542	3964	1426	22040
		RSR		83	1766	3565	3807	3228	1301	13749
		INV								3550
		INV CUM								24195
1998	300	AN	10220	8	128	213	220	190	163	927
		CUM	104405	206	2711	3132	1955	926	288	9218
		RSA ANNUAL		0	0	0	0	0	1108	1108
		RSA CUM		281	4349	6478	5542	3964	2535	23148
		RSR		75	1638	3346	3597	3037	2246	13930
		INV								3743
		INV CUM								27938
1999	315	AN	10745	7	125	211	209	176	224	952
		CUM	115150	213	2836	3343	2164	1102	512	10170
		RSA ANNUAL		0	0	0	0	0	1165	1165
		RSA CUM		281	4349	6479	5542	3964	3700	24313
		RSR		68	1513	3135	3370	2862	3188	14143
		INV								3935
		INV CUM								31873

2000	330	AN	11270	7	122	205	200	165	283	982
		CUM	126420	220	2958	3548	2363	1267	796	11152
		RSA	ANNUAL	0	0	0	0	0	1222	1222
		RSA	CUM	281	4349	6478	5542	3964	4922	25535
		RSP		60	1391	2930	3179	2697	4126	14383
		INV								4127
		INV	CUM							36000

ADVANCED TECHNOLOGY (75K) - ROR 10% (BASE CASE)

BASELINE DATA AS OF 05 SEP 79 2
FROM NPCGAS V 4.0 - 05 SEP 79 OF 09/10/79. 11.48.37.

AT ROR OF 10%

PRICE	RESERVE	AREA	C1	WELLS	PROD/W	AVE PR	INVEST
2.50	11770	3124	86	30873	381250	2.10	243612
3.50	8371	6543	76	24863	336691	2.97	311049
5.00	7094	7432	57	28242	251176	4.23	321339
7.00	5658	8106	41	30803	183690	5.99	330581
9.00	6019	11183	32	42496	141632	7.82	329805
500.00	10991	20631	32	78397	140196	11.69	500674
	------	------		------		======	
TOTAL	49903	62020		235674		5.79	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. ADVANCED TECHNOLOGY (75K) - LOW GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/10/79. 11.49.06.

AT ROR OF 10%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	12	0	0	0	0	0	12
		CUM	430	12	0	0	0	0	0	12
		RSA ANNUAL		164	0	0	0	0	0	164
		RSA CUM		164	0	0	0	0	0	164
		RSR		152	0	0	0	0	0	152
		INV								105
		INV CUM								105
1981	15	AN	478	23	0	0	0	0	0	23
		CUM	908	35	0	0	0	0	0	35
		RSA ANNUAL		182	0	0	0	0	0	182
		RSA CUM		346	0	0	0	0	0	346
		RSR		311	0	0	0	0	0	311
		INV								116
		INV CUM								221
1982	16	AN	541	34	0	0	0	0	0	34
		CUM	1449	69	0	0	0	0	0	69
		RSA ANNUAL		206	0	0	0	0	0	206
		RSA CUM		552	0	0	0	0	0	552
		RSR		483	0	0	0	0	0	483
		INV								132
		INV CUM								353
1983	18	AN	606	46	0	0	0	0	0	46
		CUM	2055	116	0	0	0	0	0	116
		RSA ANNUAL		231	0	0	0	0	0	231
		RSA CUM		783	0	0	0	0	0	783
		RSR		668	0	0	0	0	0	668
		INV								148
		INV CUM								501
1984	21	AN	682	59	0	0	0	0	0	59
		CUM	2737	175	0	0	0	0	0	175

		RSA ANNUAL		260	0	0	0	0	0	260
		RSA CUM		1043	0	0	0	0	0	1043
		RSR		868	0	0	0	0	0	868
		INV								166
		INV CUM								667
1985	23	AN	765	74	0	0	0	0	0	74
		CUM	3503	249	0	0	0	0	0	249
		RSA ANNUAL		292	0	0	0	0	0	292
		RSA CUM		1336	0	0	0	0	0	1336
		RSR		1087	0	0	0	0	0	1087
		INV								187
		INV CUM								853
1986	26	AN	859	89	0	0	0	0	0	89
		CUM	4362	338	0	0	0	0	0	338
		RSA ANNUAL		327	0	0	0	0	0	327
		RSA CUM		1663	0	0	0	0	0	1663
		RSR		1325	0	0	0	0	0	1325
		INV								209
		INV CUM								1063
1987	29	AN	964	106	0	0	0	0	0	106
		CUM	5326	444	0	0	0	0	0	444
		RSA ANNUAL		368	0	0	0	0	0	368
		RSA CUM		2031	0	0	0	0	0	2031
		RSR		1587	0	0	0	0	0	1587
		INV								235
		INV CUM								1297
1988	33	AN	1082	125	0	0	0	0	0	125
		CUM	6408	569	0	0	0	0	0	569
		RSA ANNUAL		413	0	0	0	0	0	413
		RSA CUM		2443	0	0	0	0	0	2443
		RSR		1874	0	0	0	0	0	1874
		INV								264
		INV CUM								1561
1989	37	AN	1214	146	0	0	0	0	0	146
		CUM	7622	715	0	0	0	0	0	715
		RSA ANNUAL		463	0	0	0	0	0	463
		RSA CUM		2906	0	0	0	0	0	2906

		RSR		2191	0	0	0	0	0	2191
		INV								296
		INV CUM								1857
1990	41	AN	1362	169	0	0	0	0	0	169
		CUM	8984	884	0	0	0	0	0	884
		RSA ANNUAL		519	0	0	0	0	0	519
		RSA CUM		3425	0	0	0	0	0	3425
		RSR		2542	0	0	0	0	0	2542
		INV								332
		INV CUM								2189
1991	46	AN	1527	195	0	0	0	0	0	195
		CUM	10511	1079	0	0	0	0	0	1079
		RSA ANNUAL		582	0	0	0	0	0	582
		RSA CUM		4007	0	0	0	0	0	4007
		RSR		2929	0	0	0	0	0	2929
		INV								372
		INV CUM								2561
1992	52	AN	1713	224	0	0	0	0	0	224
		CUM	12224	1302	0	0	0	0	0	1302
		RSA ANNUAL		653	0	0	0	0	0	653
		RSA CUM		4660	0	0	0	0	0	4660
		RSR		3358	0	0	0	0	0	3358
		INV								417
		INV CUM								2978
1993	58	AN	1920	256	0	0	0	0	0	256
		CUM	14144	1558	0	0	0	0	0	1558
		RSA ANNUAL		732	0	0	0	0	0	732
		RSA CUM		5392	0	0	0	0	0	5392
		RSR		3834	0	0	0	0	0	3834
		INV								468
		INV CUM								3446
1994	65	AN	2152	292	0	0	0	0	0	292
		CUM	16296	1850	0	0	0	0	0	1850
		RSA ANNUAL		820	0	0	0	0	0	820
		RSA CUM		6213	0	0	0	0	0	6213
		RSR		4362	0	0	0	0	0	4362
		INV								524

		INV CUM								3970
1995	73	AN	2412	332	0	0	0	0	0	332
		CUM	18708	2183	0	0	0	0	0	2183
		RSA ANNUAL		920	0	0	0	0	0	920
		RSA CUM		7132	0	0	0	0	0	7132
		RSR		4950	0	0	0	0	0	4950
		INV								588
		INV CUM								4557
1996	82	AN	2704	377	0	0	0	0	0	377
		CUM	21412	2560	0	0	0	0	0	2560
		RSA ANNUAL		1031	0	0	0	0	0	1031
		RSA CUM		8163	0	0	0	0	0	8163
		RSR		5604	0	0	0	0	0	5604
		INV								659
		INV CUM								5216
1997	92	AN	3031	427	0	0	0	0	0	427
		CUM	24443	2987	0	0	0	0	0	2987
		RSA ANNUAL		1156	0	0	0	0	0	1156
		RSA CUM		9319	0	0	0	0	0	9319
		RSR		6332	0	0	0	0	0	6332
		INV								738
		INV CUM								5955
1998	103	AN	3399	484	0	0	0	0	0	484
		CUM	27842	3471	0	0	0	0	0	3471
		RSA ANNUAL		1296	0	0	0	0	0	1296
		RSA CUM		10615	0	0	0	0	0	10615
		RSR		7144	0	0	0	0	0	7144
		INV								828
		INV CUM								6783
1999	115	AN	3808	525	19	0	0	0	0	544
		CUM	31650	3996	19	0	0	0	0	4015
		RSA ANNUAL		1156	262	0	0	0	0	1417
		RSA CUM		11770	262	0	0	0	0	12032
		RSR		7774	243	0	0	0	0	8017
		INV								980
		INV CUM								7763

2000	129	AN	4265	482	120	0	0	0	0	601
		CUM	35915	4478	138	0	0	0	0	4616
		RSA ANNUAL		0	1436	0	0	0	0	1436
		RSA CUM		11770	1698	0	0	0	0	13468
		RSR		7293	1559	0	0	0	0	8852
		INV								1327
		INV CUM								9089

DEFAULT GEORSK = .95

B. ADVANCED TECHNOLOGY (75K) - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/10/79. 11.49.10.

AT ROR OF 10%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	21	0	0	0	0	0	21
		CUM	770	21	0	0	0	0	0	21
		RSA ANNUAL		294	0	0	0	0	0	294
		RSA CUM		294	0	0	0	0	0	294
		RSR		272	0	0	0	0	0	272
		INV								188
		INV CUM								188
1981	45	AN	1295	53	0	0	0	0	0	53
		CUM	2065	75	0	0	0	0	0	75
		RSA ANNUAL		494	0	0	0	0	0	494
		RSA CUM		787	0	0	0	0	0	787
		RSR		713	0	0	0	0	0	713
		INV								315
		INV CUM								503
1982	60	AN	1820	95	0	0	0	0	0	95
		CUM	3885	170	0	0	0	0	0	170
		RSA ANNUAL		694	0	0	0	0	0	694
		RSA CUM		1481	0	0	0	0	0	1481
		RSR		1311	0	0	0	0	0	1311
		INV								443
		INV CUM								946
1983	75	AN	2345	146	0	0	0	0	0	146
		CUM	6230	316	0	0	0	0	0	316
		RSA ANNUAL		894	0	0	0	0	0	894
		RSA CUM		2375	0	0	0	0	0	2375
		RSR		2059	0	0	0	0	0	2059
		INV								571
		INV CUM								1518
1984	90	AN	2870	206	0	0	0	0	0	206
		CUM	9100	522	0	0	0	0	0	522

		RSA ANNUAL		1094	0	0	0	0	0	1094
		RSA CUM		3469	0	0	0	0	0	3469
		RSR		2948	0	0	0	0	0	2948
		INV								699
		INV CUM								2217
1985	105	AN	3395	273	0	0	0	0	0	273
		CUM	12495	795	0	0	0	0	0	795
		RSA ANNUAL		1294	0	0	0	0	0	1294
		RSA CUM		4764	0	0	0	0	0	4764
		RSR		3969	0	0	0	0	0	3969
		INV								827
		INV CUM								3044
1986	120	AN	3920	349	0	0	0	0	0	349
		CUM	16415	1144	0	0	0	0	0	1144
		RSA ANNUAL		1495	0	0	0	0	0	1495
		RSA CUM		6258	0	0	0	0	0	6258
		RSR		5115	0	0	0	0	0	5115
		INV								955
		INV CUM								3999
1987	135	AN	4445	431	0	0	0	0	0	431
		CUM	20860	1575	0	0	0	0	0	1575
		RSA ANNUAL		1695	0	0	0	0	0	1695
		RSA CUM		7953	0	0	0	0	0	7953
		RSR		6378	0	0	0	0	0	6378
		INV								1083
		INV CUM								5082
1988	150	AN	4970	521	0	0	0	0	0	521
		CUM	25830	2095	0	0	0	0	0	2095
		RSA ANNUAL		1895	0	0	0	0	0	1895
		RSA CUM		9848	0	0	0	0	0	9848
		RSR		7752	0	0	0	0	0	7752
		INV								1211
		INV CUM								6293
1989	165	AN	5495	605	11	0	0	0	0	616
		CUM	31325	2700	11	0	0	0	0	2711
		RSA ANNUAL		1923	152	0	0	0	0	2075
		RSA CUM		11770	152	0	0	0	0	11923

		RSR		9070	141	0	0	0	0	9212
		INV								1369
		INV CUM								7662
1990	180	AN	6020	543	156	0	0	0	0	699
		CUM	37345	3243	167	0	0	0	0	3410
		RSA ANNUAL		0	2027	0	0	0	0	2027
		RSA CUM		11770	2179	0	0	0	0	13949
		RSR		8527	2012	0	0	0	0	10539
		INV								1873
		INV CUM								9534
1991	195	AN	6545	502	289	0	0	0	0	791
		CUM	43890	3745	455	0	0	0	0	4201
		RSA ANNUAL		0	2204	0	0	0	0	2204
		RSA CUM		11770	4383	0	0	0	0	16153
		RSR		8025	3927	0	0	0	0	11952
		INV								2036
		INV CUM								11570
1992	210	AN	7070	471	418	0	0	0	0	889
		CUM	50960	4216	873	0	0	0	0	5090
		RSA ANNUAL		0	2380	0	0	0	0	2380
		RSA CUM		11770	6763	0	0	0	0	18533
		RSR		7554	5890	0	0	0	0	13444
		INV								2199
		INV CUM								13769
1993	225	AN	7595	446	479	51	0	0	0	976
		CUM	58555	4662	1352	51	0	0	0	6065
		RSA ANNUAL		0	1608	708	0	0	0	2316
		RSA CUM		11770	8371	708	0	0	0	20850
		RSR		7108	7019	657	0	0	0	14784
		INV								2391
		INV CUM								16161
1994	240	AN	8120	425	423	190	0	0	0	1038
		CUM	66675	5088	1775	241	0	0	0	7104
		RSA ANNUAL		0	0	2040	0	0	0	2040
		RSA CUM		11770	8371	2748	0	0	0	22889
		RSR		6682	6596	2507	0	0	0	15785
		INV								2609

		INV CUM								18770
1995	255	AN	8645	408	386	316	0	0	0	1110
		CUM	75320	5496	2161	558	0	0	0	8214
		RSA ANNUAL		0	0	2171	0	0	0	2171
		RSA CUM		11770	8371	4919	0	0	0	25060
		RSR		5274	6210	4362	0	0	0	16846
		INV								2778
		INV CUM								21548
1996	270	AN	9170	393	359	428	7	0	0	1187
		CUM	84490	5889	2520	986	7	0	0	9401
		RSA ANNUAL		0	0	2175	94	0	0	2269
		RSA CUM		11770	8371	7094	94	0	0	27329
		RSR		5881	5852	6108	87	0	0	17928
		INV								2951
		INV CUM								24499
1997	285	AN	9695	380	337	373	134	0	0	1225
		CUM	94185	6269	2857	1359	141	0	0	10626
		RSA ANNUAL		0	0	0	1781	0	0	1781
		RSA CUM		11770	8371	7094	1875	0	0	29110
		RSR		5502	5514	5735	1734	0	0	18484
		INV								3205
		INV CUM								27704
1998	300	AN	10220	368	320	338	247	0	0	1273
		CUM	104405	6637	3177	1697	389	0	0	11900
		RSA ANNUAL		0	0	0	1877	0	0	1877
		RSA CUM		11770	8371	7094	3752	0	0	30987
		RSR		5133	5194	5397	3364	0	0	19088
		INV								3379
		INV CUM								31083
1999	315	AN	10745	358	306	312	348	4	0	1328
		CUM	115150	6994	3483	2010	737	4	0	13227
		RSA ANNUAL		0	0	0	1906	52	0	1958
		RSA CUM		11770	8371	7094	5658	52	0	32946
		RSR		4776	4888	5084	4921	48	0	19718
		INV								3552
		INV CUM								34635

2000	330	AN	11270	348	293	293	302	119	0	1355
		CUM	126420	7342	3776	2302	1039	122	0	14582
		RSA	ANNUAL	0	0	0	0	1596	0	1596
		RSA	CUM	11770	8371	7094	5658	1648	0	34542
		RSR		4428	4595	4791	4619	1526	0	19960
		INV								3717
		INV	CUM							38351

ADVANCED TECHNOLOGY (75K) - ROR 15%

BASELINE DATA AS OF 05 SEP 79 2 STIM= 75K, ADVANCED
FROM NGGCAS V 4.0 - 05 SEP 79 OF 09/10/79. 11.48.37.

AT ROR OF 15%

PRICE	RESERVE	AREA	C1	WELLS	PROD/W	AVE PR	INVEST
2.50	3353	2220	90	8434	397558	2.30	208277
3.50	9293	6491	85	24665	376747	3.02	263125
5.00	8592	7077	72	26893	319497	4.11	304929
7.00	6288	6756	55	25672	244929	5.81	324674
9.00	4780	6719	42	25532	187211	7.88	335068
500.00	17597	32757	32	124478	141372	13.01	437366
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TOTAL	49903	62020		235674		7.71	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. ADVANCED TECHNOLOGY (75K) - LOW GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/13/79. 05.37.30.

AT ROR OF 15%

YEAR	RIGS		WELLS	GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU) 2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	12	0	0	0	0	0	12
		CUM	430	12	0	0	0	0	0	12
		RSA ANNUAL		171	0	0	0	0	0	171
		RSA CUM		171	0	0	0	0	0	171
		RSP		159	0	0	0	0	0	159
		INV								90
		INV CUM								90
1981	15	AN	478	24	0	0	0	0	0	24
		CUM	908	36	0	0	0	0	0	36
		RSA ANNUAL		190	0	0	0	0	0	190
		RSA CUM		361	0	0	0	[illegible]	0	361
		RSP		325	0	0	0	0	0	325
		INV								100
		INV CUM								189
1982	16	AN	541	36	0	0	0	0	0	36
		CUM	1449	72	0	0	0	0	0	72
		RSA ANNUAL		215	0	0	0	0	0	215
		RSA CUM		576	0	0	0	0	0	576
		RSP		504	0	0	0	0	0	504
		INV								113
		INV CUM								302
1983	18	AN	606	48	0	0	0	0	0	48
		CUM	2055	121	0	0	0	0	0	121
		RSA ANNUAL		241	0	0	0	0	0	241
		RSA CUM		817	0	0	0	0	0	817
		RSP		696	0	0	0	0	0	696
		INV								126
		INV CUM								428
1984	21	AN	682	62	0	0	0	0	0	62
		CUM	2737	183	[illegible]	[illegible]	0	0	0	183

		RSA ANNUAL		271	0	0	0	0	0	271
		RSA CUM		1088	0	0	0	0	0	1088
		RSP		905	0	0	0	0	0	905
		INV								142
		INV CUM								570
1985	23	AN	766	77	0	0	0	0	0	77
		CUM	3503	259	0	0	0	0	0	259
		RSA ANNUAL		305	0	0	0	0	0	305
		RSA CUM		1393	0	0	0	0	0	1393
		RSP		1133	0	0	0	0	0	1133
		INV								160
		INV CUM								730
1986	26	AN	859	93	0	0	0	0	0	93
		CUM	4362	352	0	0	0	0	0	352
		RSA ANNUAL		342	0	0	0	0	0	342
		RSA CUM		1734	0	0	0	0	0	1734
		RSP		1382	0	0	0	0	0	1382
		INV								179
		INV CUM								909
1987	29	AN	964	111	0	0	0	0	0	111
		CUM	5326	463	0	0	0	0	0	463
		RSA ANNUAL		383	0	0	0	0	0	383
		RSA CUM		2117	0	0	0	0	0	2117
		RSP		1655	0	0	0	0	0	1655
		INV								201
		INV CUM								1109
1988	33	AN	1082	130	0	0	0	0	0	130
		CUM	6408	593	0	0	0	0	0	593
		RSA ANNUAL		430	0	0	0	0	0	430
		RSA CUM		2548	0	0	0	0	0	2548
		RSP		1954	0	0	0	0	0	1954
		INV								225
		INV CUM								1335
1989	37	AN	1214	152	0	0	0	0	0	152
		CUM	7622	745	0	0	0	0	0	745
		RSA ANNUAL		483	0	0	0	0	0	483
		RSA CUM		3030	0	0	0	0	0	3030

		RSP		2285	0	0	0	0	0	2285
		INV								253
		INV CUM								1587
1990	41	AN	1362	160	15	0	0	0	0	175
		CUM	8984	906	15	0	0	0	0	921
		RSA ANNUAL		323	207	0	0	0	0	530
		RSA CUM		3353	207	0	0	0	0	3560
		RSP		2447	192	0	0	0	0	2640
		INV								314
		INV CUM								1901
1991	46	AN	1527	146	54	0	0	0	0	200
		CUM	10511	1052	69	0	0	0	0	1121
		RSA ANNUAL		0	575	0	0	0	0	575
		RSA CUM		3353	782	0	0	0	0	4136
		RSP		2301	713	0	0	0	0	3015
		INV								402
		INV CUM								2303
1992	52	AN	1713	136	92	0	0	0	0	228
		CUM	12224	1188	161	0	0	0	0	1349
		RSA ANNUAL		0	645	0	0	0	0	645
		RSA CUM		3353	1428	0	0	0	0	4781
		RSP		2165	1267	0	0	0	0	3432
		INV								451
		INV CUM								2754
1993	58	AN	1920	129	131	0	0	0	0	260
		CUM	14144	1317	292	0	0	0	0	1609
		RSA ANNUAL		0	723	0	0	0	0	723
		RSA CUM		3353	2151	0	0	0	0	5504
		RSP		2036	1859	0	0	0	0	3895
		INV								505
		INV CUM								3259
1994	65	AN	2152	122	173	0	0	0	0	295
		CUM	16296	1439	465	0	0	0	0	1904
		RSA ANNUAL		0	811	0	0	0	0	811
		RSA CUM		3353	2962	0	0	0	0	6315
		RSP		1914	2497	0	0	0	0	4411
		INV								566

		INV CUM								3825
1995	73	AN	2412	117	217	0	0	0	0	334
		CUM	18708	1556	682	C	C	0	0	2238
		RSA ANNUAL		0	909	0	C	0	C	909
		RSA CUM		3353	3871	0	0	0	C	7224
		RSP		1797	3189	0	0	0	0	4985
		INV								635
		INV CUM								4460
1996	82	AN	2704	113	256	0	C	0	C	379
		CUM	21412	1669	948	0	0	0	C	2617
		RSA ANNUAL		0	1019	0	0	0	0	1019
		RSA CUM		3353	4889	0	0	0	C	8242
		RSP		1684	3942	0	0	0	C	5626
		INV								711
		INV CUM								5171
1997	92	AN	3031	109	319	C	0	0	0	428
		CUM	24443	1778	1267	0	0	0	C	3045
		RSA ANNUAL		0	1142	C	0	0	C	1142
		RSA CUM		3353	6031	0	0	0	0	9384
		RSP		1575	4764	0	0	0	0	6339
		INV								798
		INV CUM								5969
1998	103	AN	3399	105	378	0	0	0	C	483
		CUM	27842	1883	1645	0	0	0	C	3528
		RSA ANNUAL		0	1281	0	C	C	C	1281
		RSA CUM		3353	7312	0	0	0	0	10665
		RSP		1470	5667	0	0	0	0	7136
		INV								894
		INV CUM								6863
1999	115	AN	3808	102	443	0	0	0	C	546
		CUM	31650	1986	2088	0	0	0	0	4074
		RSA ANNUAL		0	1435	0	C	0	0	1435
		RSA CUM		3353	8746	0	0	0	0	12100
		RSP		1368	6658	0	0	0	C	8026
		INV								1002
		INV CUM								7865

2000	129	AN	4265	100	439	65	0	0	0	603
		CUM	35915	2085	2527	65	0	0	0	4677
		RSA ANNUAL		0	546	900	0	0	0	1446
		RSA CUM		3353	9293	900	0	0	0	13545
		RSP		1268	6765	834	0	0	0	8868
		INV								1240
		INV CUM								9105

B. ADVANCED TECHNOLOGY (75K) - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/13/79. 05.37.32.

AT ROR OF 15%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	22	0	0	0	0	0	22
		CUM	770	22	0	0	0	0	0	22
		RSA ANNUAL		306	0	0	0	0	0	306
		RSA CUM		306	0	0	0	0	0	306
		RSP		284	0	0	0	0	0	284
		INV								160
		INV CUM								160
1981	45	AN	1295	56	0	0	0	0	0	56
		CUM	2065	78	0	0	0	0	0	78
		RSA ANNUAL		515	0	0	0	0	0	515
		RSA CUM		821	0	0	0	0	0	821
		RSP		743	0	0	0	0	0	743
		INV								270
		INV CUM								430
1982	60	AN	1820	99	0	0	0	0	0	99
		CUM	3885	177	0	0	0	0	0	177
		RSA ANNUAL		724	0	0	0	0	0	724
		RSA CUM		1545	0	0	0	0	0	1545
		RSP		1368	0	0	0	0	0	1368
		INV								379
		INV CUM								809
1983	75	AN	2345	152	0	0	0	0	0	152
		CUM	6230	329	0	0	0	0	0	329
		RSA ANNUAL		932	0	0	0	0	0	932
		RSA CUM		2477	0	0	0	0	0	2477
		RSP		2147	0	0	0	0	0	2147
		INV								488
		INV CUM								1296
1984	90	AN	2870	195	18	0	0	0	0	214
		CUM	9100	525	18	0	0	0	0	543

		RSA ANNUAL		876	251	0	0	0	0	1127
		RSA CUM		3353	251	0	0	0	0	3604
		RSP		2828	233	0	0	0	0	3061
		INV								634
		INV CUM								1932
1985	105	AN	3395	172	108	0	0	0	0	279
		CUM	12495	696	126	0	0	0	0	822
		RSA ANNUAL		0	1279	0	0	0	0	1279
		RSA CUM		3353	1530	0	0	0	0	4883
		RSP		2657	1404	0	0	0	0	4061
		INV								893
		INV CUM								2825
1986	120	AN	3920	156	197	0	0	0	0	353
		CUM	16415	853	322	0	0	0	0	1175
		RSA ANNUAL		0	1477	0	0	0	0	1477
		RSA CUM		3353	3007	0	0	0	0	6360
		RSP		2501	2635	0	0	0	0	5185
		INV								1031
		INV CUM								3857
1987	135	AN	4445	145	289	0	0	0	0	434
		CUM	20860	997	611	0	0	0	0	1608
		RSA ANNUAL		0	1675	0	0	0	0	1675
		RSA CUM		3353	4681	0	0	0	0	8034
		RSP		2356	4070	0	0	0	0	6426
		INV								1170
		INV CUM								5026
1988	150	AN	4970	136	386	0	0	0	0	522
		CUM	25830	1133	997	0	0	0	0	2130
		RSA ANNUAL		0	1872	0	0	0	0	1872
		RSA CUM		3353	6554	0	0	0	0	9907
		RSP		2220	5557	0	0	0	0	7777
		INV								1308
		INV CUM								6334
1989	165	AN	5495	129	488	0	0	0	0	616
		CUM	31325	1262	1484	0	0	0	0	2746
		RSA ANNUAL		0	2070	0	0	0	0	2070
		RSA CUM		3353	8624	0	0	0	0	11977

		R SP		2091	7140	0	0	0	0	9231
		INV								1446
		INV CUM								7780
1990	180	AN	6020	123	479	98	0	0	0	700
		CUM	37345	1385	1953	98	0	0	0	3447
		RSA ANNUAL		0	669	1356	0	0	0	2025
		RSA CUM		3353	9293	1356	0	0	0	14002
		R SP		1968	7329	1258	0	0	0	10555
		INV								1761
		INV CUM								9541
1991	195	AN	6545	118	433	232	0	0	0	784
		CUM	43890	1503	2397	331	0	0	0	4230
		RSA ANNUAL		0	0	2091	0	0	0	2091
		RSA CUM		3353	9293	3448	0	0	0	16093
		R SP		1850	6896	3117	0	0	0	11863
		INV								1996
		INV CUM								11537
1992	210	AN	7070	113	401	360	0	0	0	875
		CUM	50960	1616	2798	690	0	0	0	5105
		RSA ANNUAL		0	0	2259	0	0	0	2259
		RSA CUM		3353	9293	5706	0	0	0	18352
		R SP		1737	6495	5016	0	0	0	13247
		INV								2156
		INV CUM								13693
1993	225	AN	7595	110	376	486	0	0	0	972
		CUM	58555	1726	3174	1176	0	0	0	6076
		RSA ANNUAL		0	0	2427	0	0	0	2427
		RSA CUM		3353	9293	8133	0	0	0	20779
		R SP		1627	6118	6957	0	0	0	14702
		INV								2316
		INV CUM								16009
1994	240	AN	8120	106	357	457	118	0	0	1038
		CUM	66675	1832	3531	1633	118	0	0	7115
		RSA ANNUAL		0	0	459	1637	0	0	2096
		RSA CUM		3353	9293	8592	1637	0	0	22875
		R SP		1521	5762	6959	1518	0	0	15760
		INV								2608

		INV CUM								18617
1995	255	AN	8645	103	340	412	251	0	0	1106
		CUM	75320	1935	3871	2045	369	0	0	8221
		RSA ANNUAL		0	0	0	2117	0	0	2117
		RSA CUM		3353	9293	8592	3754	0	0	24992
		RSP		1418	5422	6547	3385	0	0	16771
		INV								2807
		INV CUM								21424
1996	270	AN	9170	100	326	380	375	0	0	1182
		CUM	84490	2035	4197	2426	745	0	0	9403
		RSA ANNUAL		0	0	0	2246	0	0	2246
		RSA CUM		3353	9293	8592	6000	0	0	27238
		RSP		1318	5096	6167	5255	0	0	17835
		INV								2977
		INV CUM								24401
1997	285	AN	9695	98	314	356	345	115	0	1227
		CUM	94185	2133	4511	2781	1090	115	0	10630
		RSA ANNUAL		0	0	0	288	1595	0	1883
		RSA CUM		3353	9293	8592	6288	1595	0	29121
		RSP		1220	4782	5811	5198	1480	0	18491
		INV								3236
		INV CUM								27637
1998	300	AN	10220	95	303	336	309	234	0	1278
		CUM	104405	2229	4814	3117	1399	349	0	11908
		RSA ANNUAL		0	0	0	0	1913	0	1913
		RSA CUM		3353	9293	8592	6288	3509	0	31034
		RSP		1125	4479	5475	4889	3159	0	19126
		INV								3424
		INV CUM								31062
1999	315	AN	10745	93	294	320	284	290	40	1322
		CUM	115150	2322	5107	3437	1683	640	40	13229
		RSA ANNUAL		0	0	0	0	1271	559	1830
		RSA CUM		3353	9293	8592	6288	4780	559	32864
		RSP		1031	4185	5155	4605	4140	519	19635
		INV								4005
		INV CUM								35066

2000	330	AN	11270	91	285	306	265	253	149	1350
		CUM	126420	2413	5392	3744	1948	893	189	14579
		RSA	ANNUAL	0	0	0	0	0	1593	1593
		RSA	CUM	2353	9293	8592	6288	4780	2152	34458
		RSR		940	3900	4849	4340	3887	1963	19879
		INV								4929
		INV	CUM							39995

ADVANCED TECHNOLOGY (75K) - ROR 20%

BASELINE DATA AS OF 05 SEP 79 2
FROM NPCGAS V 4.0 - 05 SEP 79 OF 09/10/79. 11.48.37.

			AT ROR OF 20%				
PRICE	RESERVE	AREA	C1	WELLS	PROD/W	AVE PR	INVEST
2.50	0	0	0	0	0	0.00	0
3.50	6541	4542	86	17261	378926	3.10	215047
5.00	10254	7077	86	26892	381290	4.27	306696
7.00	7198	6590	65	25044	287423	6.00	321055
9.00	4903	5984	49	22739	215643	7.89	310235
500.00	21007	37826	33	143739	146149	15.86	422469
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TOTAL	49903	62020		235674		9.61	

A. LOW GROWTH DRILLING SCHEDULE

B. HIGH GROWTH DRILLING SCHEDULE

A. ADVANCED TECHNOLOGY (75K) - LOW GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/13/79. 05.41.47.

AT ROR OF 20%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	13	AN	430	0	12	0	0	0	0	12
		CUM	430	0	12	0	0	0	0	12
		RSA ANNUAL		0	163	0	0	0	0	163
		RSA CUM		0	163	0	0	0	0	163
		RSP		0	151	0	0	0	0	151
		INV								92
		INV CUM								92
1981	15	AN	478	0	23	0	0	0	0	23
		CUM	908	0	35	0	0	0	0	35
		RSA ANNUAL		0	181	0	0	0	0	181
		RSA CUM		0	344	0	0	0	0	344
		RSP		0	309	0	0	0	0	309
		INV								103
		INV CUM								195
1982	16	AN	541	0	34	0	0	0	0	34
		CUM	1449	0	69	0	0	0	0	69
		RSA ANNUAL		0	205	0	0	0	0	205
		RSA CUM		0	549	0	0	0	0	549
		RSP		0	480	0	0	0	0	480
		INV								116
		INV CUM								312
1983	18	AN	606	0	46	0	0	0	0	46
		CUM	2055	0	115	0	0	0	0	115
		RSA ANNUAL		0	230	0	0	0	0	230
		RSA CUM		0	779	0	0	0	0	779
		RSP		0	664	0	0	0	0	664
		INV								130
		INV CUM								442
1984	21	AN	682	0	59	0	0	0	0	59
		CUM	2737	0	174	0	0	0	0	174

		RSA ANNUAL		0	258	0	0	0	0	258
		RSA CUM		0	1037	0	0	0	0	1037
		RSP		0	863	0	0	0	0	863
		INV								147
		INV CUM								589
1985	23	AN	766	0	73	0	0	0	0	73
		CUM	3502	0	247	0	0	0	0	247
		RSA ANNUAL		0	290	0	0	0	0	290
		RSA CUM		0	1327	0	0	0	0	1327
		RSP		0	1080	0	0	0	0	1080
		INV								165
		INV CUM								753
1986	26	AN	860	0	88	0	0	0	0	88
		CUM	4362	0	336	0	0	0	0	336
		RSA ANNUAL		0	325	0	0	0	0	325
		RSA CUM		0	1653	0	0	0	0	1653
		RSP		0	1317	0	0	0	0	1317
		INV								185
		INV CUM								938
1987	29	AN	964	0	105	0	0	0	0	105
		CUM	5326	0	441	0	0	0	0	441
		RSA ANNUAL		0	365	0	0	0	0	365
		RSA CUM		0	2018	0	0	0	0	2018
		RSP		0	1577	0	0	0	0	1577
		INV								207
		INV CUM								1145
1988	33	AN	1082	0	124	0	0	0	0	124
		CUM	6408	0	565	0	0	0	0	565
		RSA ANNUAL		0	410	0	0	0	0	410
		RSA CUM		0	2428	0	0	0	0	2428
		RSP		0	1863	0	0	0	0	1863
		INV								233
		INV CUM								1378
1989	37	AN	1214	0	145	0	0	0	0	145
		CUM	7622	0	710	0	0	0	0	710
		RSA ANNUAL		0	460	0	0	0	0	460
		RSA CUM		0	2888	0	0	0	0	2888

		R SP		0	2178	0	0	0	0	2178
		INV								261
		INV CUM								1639
1990	41	AN	1362	0	168	0	0	0	0	168
		CUM	8984	0	878	0	0	0	0	878
		RSA ANNUAL		0	516	0	0	0	0	516
		RSA CUM		0	3404	0	0	0	0	3404
		R SP		0	2526	0	0	0	0	2526
		INV								293
		INV CUM								1932
1991	46	AN	1527	0	194	0	0	0	0	194
		CUM	10511	0	1072	0	0	0	0	1072
		RSA ANNUAL		0	579	0	0	0	0	579
		RSA CUM		0	3983	0	0	0	0	3983
		R SP		0	2911	0	0	0	0	2911
		INV								328
		INV CUM								2260
1992	52	AN	1713	0	222	0	0	0	0	222
		CUM	12224	0	1294	0	0	0	0	1294
		RSA ANNUAL		0	649	0	0	0	0	649
		RSA CUM		0	4632	0	0	0	0	4632
		R SP		0	3338	0	0	0	0	3338
		INV								368
		INV CUM								2629
1993	58	AN	1920	0	254	0	0	0	0	254
		CUM	14144	0	1549	0	0	0	0	1549
		RSA ANNUAL		0	728	0	0	0	0	728
		RSA CUM		0	5360	0	0	0	0	5360
		R SP		0	3811	0	0	0	0	3811
		INV								413
		INV CUM								3042
1994	65	AN	2152	0	290	0	0	0	0	290
		CUM	16296	0	1839	0	0	0	0	1839
		RSA ANNUAL		0	815	0	0	0	0	815
		RSA CUM		0	6175	0	0	0	0	6175
		R SP		0	4336	0	0	0	0	4336
		INV								463

		INV CUM								3504
1995	73	AN	2412	0	291	40	0	0	0	330
		CUM	18708	0	2130	40	0	0	0	2170
		RSA ANNUAL		0	366	552	0	0	0	917
		RSA CUM		0	6541	552	0	0	0	7092
		RSP		0	4411	512	0	0	0	4923
		INV								651
		INV CUM								4156
1996	82	AN	2704	0	268	108	0	0	0	375
		CUM	21412	0	2398	147	0	0	0	2545
		RSA ANNUAL		0	0	1031	0	0	0	1031
		RSA CUM		0	6541	1583	0	0	0	8123
		RSP		0	4143	1435	0	0	0	5578
		INV								829
		INV CUM								4985
1997	92	AN	3031	0	252	174	0	0	0	426
		CUM	24443	0	2649	322	0	0	0	2971
		RSA ANNUAL		0	0	1156	0	0	0	1156
		RSA CUM		0	6541	2738	0	0	0	9279
		RSP		0	3892	2416	0	0	0	6308
		INV								930
		INV CUM								5915
1998	103	AN	3399	0	239	244	0	0	0	482
		CUM	27842	0	2888	565	0	0	0	3453
		RSA ANNUAL		0	0	1296	0	0	0	1296
		RSA CUM		0	6541	4034	0	0	0	10575
		RSP		0	3653	3469	0	0	0	7122
		INV								1042
		INV CUM								6957
1999	115	AN	3808	0	228	317	0	0	0	545
		CUM	31650	0	3116	882	0	0	0	3998
		RSA ANNUAL		0	0	1452	0	0	0	1452
		RSA CUM		0	6541	5486	0	0	0	12027
		RSP		0	3425	4604	0	0	0	8029
		INV								1168
		INV CUM								8125

2000	129	AN	4265	0	219	396	0	0	0	616
		CUM	35915	0	3335	1279	0	0	0	4614
		RSA ANNUAL		0	0	1626	0	0	0	1626
		RSA CUM		0	6541	7112	0	0	0	13653
		RSR		0	3206	5833	0	0	0	9039
		INV								1308
		INV CUM								9433

B. ADVANCED TECHNOLOGY (75K) - HIGH GROWTH

DRILLING SCENARIO ANALYSIS - VERSION 3.0 - 10 SEP 79

09/13/79. 05.41.49.

AT ROR OF 20%

GAS EXTRACTED (BCF) BY PRICE RANGE ($/MMBTU)

YEAR	RIGS		WELLS	2.50	3.50	5.00	7.00	9.00	500.00	TOTAL
1980	30	AN	770	0	21	0	0	0	0	21
		CUM	770	0	21	0	0	0	0	21
		RSA ANNUAL		0	292	0	0	0	0	292
		RSA CUM		0	292	0	0	0	0	292
		RSP		0	271	0	0	0	0	271
		INV								166
		INV CUM								166
1981	45	AN	1295	0	53	0	0	0	0	53
		CUM	2065	0	74	0	0	0	0	74
		RSA ANNUAL		0	491	0	0	0	0	491
		RSA CUM		0	782	0	0	0	0	782
		RSP		0	708	0	0	0	0	708
		INV								278
		INV CUM								444
1982	60	AN	1820	0	95	0	0	0	0	95
		CUM	3885	0	169	0	0	0	0	169
		RSA ANNUAL		0	690	0	0	0	0	690
		RSA CUM		0	1472	0	0	0	0	1472
		RSP		0	1303	0	0	0	0	1303
		INV								391
		INV CUM								835
1983	75	AN	2345	0	145	0	0	0	0	145
		CUM	6230	0	314	0	0	0	0	314
		RSA ANNUAL		0	889	0	0	0	0	889
		RSA CUM		0	2361	0	0	0	0	2361
		RSP		0	2047	0	0	0	0	2047
		INV								504
		INV CUM								1340
1984	90	AN	2870	0	205	0	0	0	0	205
		CUM	9100	0	519	0	0	0	0	519

		RSA ANNUAL		0	1088	0	0	0	0	1088
		RSA CUM		0	3448	0	0	0	0	3448
		RSP		0	2930	0	0	0	0	2930
		INV								517
		INV CUM								1957
1985	105	AN	3395	0	272	0	0	0	0	272
		CUM	12495	0	790	0	0	0	0	790
		RSA ANNUAL		0	1286	0	0	0	0	1286
		RSA CUM		0	4735	0	0	0	0	4735
		RSP		0	3944	0	0	0	0	3944
		INV								730
		INV CUM								2687
1986	120	AN	3920	0	346	0	0	0	0	346
		CUM	16415	0	1137	0	0	0	0	1137
		RSA ANNUAL		0	1485	0	0	0	0	1485
		RSA CUM		0	6220	0	0	0	0	6220
		RSP		0	5083	0	0	0	0	5083
		INV								843
		INV CUM								3530
1987	135	AN	4445	0	330	99	0	0	0	429
		CUM	20860	0	1467	99	0	0	0	1566
		RSA ANNUAL		0	321	1372	0	0	0	1693
		RSA CUM		0	6541	1372	0	0	0	7913
		RSP		0	5074	1273	0	0	0	6347
		INV								1286
		INV CUM								4816
1988	150	AN	4970	0	300	219	0	0	0	519
		CUM	25830	0	1767	318	0	0	0	2085
		RSA ANNUAL		0	0	1895	0	0	0	1895
		RSA CUM		0	6541	3267	0	0	0	9808
		RSP		0	4775	2949	0	0	0	7723
		INV								1524
		INV CUM								6340
1989	165	AN	5495	0	278	337	0	0	0	615
		CUM	31325	0	2044	656	0	0	0	2700
		RSA ANNUAL		0	0	2095	0	0	0	2095
		RSA CUM		0	6541	5362	0	0	0	11903

		RSR		0	4496	4707	0	0	0	9203
		INV								1685
		INV CUM								8025
1990	180	AN	6020	0	261	457	0	0	0	718
		CUM	37345	0	2306	1112	0	0	0	3418
		RSA ANNUAL		0	0	2295	0	0	0	2295
		RSA CUM		0	6541	7658	0	0	0	14198
		RSP		0	4235	6545	0	0	0	10780
		INV								1846
		INV CUM								9872
1991	195	AN	6545	0	248	579	0	0	0	827
		CUM	43890	0	2554	1692	0	0	0	4246
		RSA ANNUAL		0	0	2496	0	0	0	2496
		RSA CUM		0	6541	10153	0	0	0	16694
		RSP		0	3987	8461	0	0	0	12448
		INV								2007
		INV CUM								11879
1992	210	AN	7070	0	237	518	142	0	0	897
		CUM	50960	0	2791	2210	142	0	0	5142
		RSA ANNUAL		0	0	100	1956	0	0	2057
		RSA CUM		0	6541	10254	1956	0	0	18751
		RSP		0	3750	8043	1815	0	0	13608
		INV								2266
		INV CUM								14145
1993	225	AN	7595	0	227	472	275	0	0	974
		CUM	58555	0	3018	2683	416	0	0	6117
		RSA ANNUAL		0	0	0	2183	0	0	2183
		RSA CUM		0	6541	10254	4139	0	0	20934
		RSP		0	3523	7571	3723	0	0	14817
		INV								2438
		INV CUM								16583
1994	240	AN	8120	0	219	439	402	0	0	1060
		CUM	66675	0	3237	3121	819	0	0	7177
		RSA ANNUAL		0	0	0	2334	0	0	2334
		RSA CUM		0	6541	10254	6473	0	0	23268
		RSP		0	3304	7133	5654	0	0	16091
		INV								2607

		INV CUM								19190
1995	255	AN	8645	0	212	412	401	96	0	1120
		CUM	75320	0	3448	3534	1219	96	0	8297
		RSA ANNUAL		0	0	0	725	1320	0	2045
		RSA CUM		0	6541	10254	7198	1320	0	25313
		RSP		0	3093	6720	5979	1225	0	17016
		INV								2709
		INV CUM								21900
1996	270	AN	9170	0	205	391	357	222	0	1175
		CUM	84490	0	3653	3925	1577	318	0	9472
		RSA ANNUAL		0	0	0	0	1977	0	1977
		RSA CUM		0	6541	10254	7198	3298	0	27290
		RSP		0	2838	6329	5621	2980	0	17818
		INV								2845
		INV CUM								24744
1997	285	AN	9695	0	199	373	328	304	24	1228
		CUM	94185	0	3852	4298	1904	622	24	10700
		RSA ANNUAL		0	0	0	0	1606	329	1934
		RSA CUM		0	6541	10254	7198	4903	329	29225
		RSP		0	2688	5956	5294	4282	305	18525
		INV								3260
		INV CUM								28005
1998	300	AN	10220	0	194	358	305	263	128	1248
		CUM	104405	0	4046	4656	2209	885	152	11948
		RSA ANNUAL		0	0	0	0	0	1494	1494
		RSA CUM		0	6541	10254	7198	4903	1822	30718
		RSP		0	2495	5597	4989	4019	1671	18770
		INV								4318
		INV CUM								32322
1999	315	AN	10745	0	189	345	288	238	220	1279
		CUM	115150	0	4235	5001	2497	1122	372	13227
		RSA ANNUAL		0	0	0	0	0	1570	1570
		RSA CUM		0	6541	10254	7198	4903	3393	32289
		RSP		0	2306	5252	4701	3781	3021	19061
		INV								4539
		INV CUM								36862

2000	330	AN	11270	0	185	333	273	219	307	1318
		CUM	126420	0	4420	5335	2770	1341	679	14545
		RSA	ANNUAL	0	0	0	0	0	1647	1647
		RSA	CUM	0	6541	10254	7198	4903	5040	33936
		RSR		0	2121	4919	4428	3562	4361	19391
		INV								4761
		INV	CUM							41623